BEFORE THE
CALIFORNIA ENERGY COMMISSION (CEC)

In the matter of 2013 Integrated Energy Policy Report (2013 IEPR)	Docket No. 13-IEP-1D Lead Commissioner Workshop on Evaluating Electricity Sector Needs in 2030

LEAD COMMISIONER WORKSHOP
ON
EVALUATING ELECTRICITY SECTOR NEEDS IN 2030

California Energy Commission
Hearing Room A
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Sacramento, California

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9:30 A.M.

Reported by:
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APPEARANCES

COMMISSIONERS PRESENT

Robert B. Weisenmiller, Chair
Andrew McAllister, Lead Commissioner 2013 IEPR

STAFF PRESENT

Suzanne Korosec, IEPR Lead
David Vidaver

WORKSHOP PRESENTERS

Shucheng Liu, California Independent System Operator (CAISO)
Tim Tutt, Sacramento Municipal Utilities District (SMUD)
Mike Webster, Los Angeles Department of Water and Power (LADWP)
Jeffery Greenblatt, California Council on Science and Technology (CCST)
Jimmy Nelson, Renewable & Appropriate Energy Laboratory, UC Berkeley
Christopher Yang, Institute of Transportation Studies, UC Davis
Lorenzo Kristov, CAISO
Lee S. Friedman, Goldman School of Public Policy, UC Berkeley

Panelists

Ray Williams, Pacific Gas & Electric (PG&E)
Dhaval Dagli, Southern California Edison (SCE)
Sierra Martinez, Natural Resources Defense Council (NRDC)
Laura Wisland, Union of Concerned Scientists
Matt Vespa, Sierra Club

Also Present (* by phone)

Public Comment

V. John White, CEERT
Ray Pingle, Sierra Club
Erica Brand, Project Director, California Renewable Energy Initiative, California Nature Conservancy
*Shalini Swaroop, Marin

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P R O C E E D I N G S

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[Meeting already in progress]

MR. VIDAVER: I fiddled with the prices a bit to reduce the impact of a spike in each series, and not all months of the year exhibited such shifts. But here we can see a shift in the value of energy from mid-day to early evening hours with implications for time of use rates and the relative value of efficiency programs and standards.

Increased reliance on intermittent generation resources has had a dramatic effect on electricity planning. Deterministic scenario-based modeling using hourly data has been replaced by stochastic analysis and much shorter time steps, and requiring an understanding of the site specific relationships between weather and solar and wind output. Simulated data for a limited number of weather years is being used for modeling purposes. We are only now beginning to produce enough real data to assess the accuracy of the generation profiles that we use.

The impact of intermittency on operations is well known, higher reserves, and the need for additional flexible capacity subject to dispatch by the Balancing Authority, improved forecasting, shorter scheduling time steps, and market regionalization are all being used to deal with this need in the near term. The targeted energy efficiency, the provision of ramping services by loads, and inter-hour storage will be needed in quantity through 2030 if we are to address intermittency in a fashion that minimizes greenhouse gas emissions.

This, too, is well known: the Public Utilities Commission's Energy Efficiency Demand Response and Storage Proceedings are testimony to the State's efforts in this regard.

One of the more significant uncertainties through 2030 will be load growth and energy efficiency savings. Using the Energy Commission Draft 2013 Forecast Scenarios, and combining them with different achievable energy efficiency scenarios from the preceding IEPR, then extrapolating them out to 2030, one can see how demand might grow. These are crude and unvetted estimates of growth and they're intended solely for illustration, so don't take them too seriously.

But a linear extrapolation of growth might not be a reasonable assumption; higher prices in outer years may encourage more energy efficiency and customer side of the meter solar. Zero Net Energy homes, not a factor in the current planning horizon, have the potential to increase rooftop solar by 3,000 megawatts over the 2020's on new homes, alone. Accelerating EV deployment and climate change will result in increased consumption.

As importantly, improving communications technology and time of use rates will reshape load profiles. Supply uncertainties include two major potential retirements that are also related to those resources that will reduce the need for gas-fired generation. These uncertainties become all the more salient if we increase our reliance on renewable energy in the 2020s.

This graph turns those low growth trends into incremental renewable energy requirements. If the RPS is raised for 2030, 26 terawatt hours, it doesn't sound like much given our recent progress. Fifty-four terawatt hours over 10 years would be roughly equal to our planned procurement this decade.

This table indicates a contribution of renewable technologies to an increase of 26 terawatt hours. The capacity factors may not be to your liking, but the point is the desire to propose solar additions in the 2020s may consist of 5,000 megawatts on each side of the meter, if not more. The potential implications of this for complimentary resource needs should surely be investigated.

And finally, we return full circle. A panel discussion this afternoon will hopefully bring forth initial thoughts regarding these questions. We welcome their being addressed in written comments, as well. That concludes my presentation and, after questions, I'll turn this over to people far smarter than I. Thank you.

CHAIRMAN WEISENMILLER: I guess the one I have, David, is what sort of range are you seeing here for ZEV in the mix between hydrogen and electricity out to 2030, if you got into that, really?

MR. VIDAVER: One of our presenters today is going to hopefully discuss that issue, Christopher Yang from the U.C. Davis Institute of Transportation is going to present that. I personally don't have any information to provide to you.

CHAIRMAN WEISENMILLER: Okay, that's fine. Thank you.

MS. KOROSEC: Thank you, David. Our next speaker is going to be Shucheng Liu from the California ISO.

MR. LIU: Chairman, Commissioners, and everybody, thank you for the opportunity to talk about the ISO's view of meeting the challenge of integrated high level of renewable energy into the system.

California is the lead of the country in renewable integration. The renewable generation brings now clean energy to the customers and reduced emissions. At the same time, it proposes a challenge for the ISO to operate the system reliably with such a high level of renewable energy.

The challenge comes from the intermittency of renewable energy. My presentation today focuses on the resource solution to address the challenge. And Lorenzo Kristov will talk about the role of transmission planning in the afternoon.

As you all know, California is on track to meet the 33 percent renewable portfolio standard by 2020 or sooner. To get ready for that, the ISO and the PUC are working together to develop the tools needed to maintain reliability.

One of the tools is the flexible resource adequacy requirement. Currently, load serving entities are required to procure capacity up to 115 percent over their peak load. And besides that, there is no requirement about how much the resource can do in terms of flexibility or ramping.

ISO and the PUC haven't developed their requirement. To add another submission to our requirement. So besides the capacity you need to prove that you have 115 percent capacity. The capacity has to be able to meet certain ramping requirements. The standard we say that is for the monthly maximum 3R continuous ramping requirements in the ISO net load, so that requirement is located to the lowest serving entities. That requirement now has to get approved by the CPUC and it will be in place for the 2015 showing, so that means next year when the low server entities go out to procure capacity to meet the RA requirement, the flexibility requirement will be enforced.

And the next one we are working on is the multi-year forward procured RA resource. The purpose of this requirement is to ensure that there is a steady economic incentive for the investment and for the existing resource. We are looking at the RA obligation going out three years, so that the resource or the investor can see the coming capacity revenue from the contract could be awarded for the RA requirement. And from year 4 to year 9 or 10, we are trying to put together non-binding reliability assessment; basically, that's how much RA capacity we might need and what type of capacity, and non-binding is more directional so that it can help the investment decisions.

The ISO is conducting the Long Term Procurement Plan for the CPUC proceeding. In this study, we are looking out 10 years, we are looking at the year 2022 and we are determining what additional capacity and how much is needed. And it will also help to see to determine what will be the different -- the combination of the resources that will be needed, and it helps the

PUC in deciding the procurement ruling.

The current ISO market, we also have the flexible capacity product in force. ISO tried to reserve certain portions of on line flexible capacity, both upward and downward in the market, in order to be used in the real-time market. This is one of the measures that, whenever we have expected changes from a renewable generation, we should have enough flexible resource to meet together the changes.

In the renewable integration, flexibility of capacity is key. With flexible capacity, you can use it to meet energy ramp from one hour to the next. You can use it to follow the loads within an hour, and those changes come constantly, and we have to be able to follow that load upward or downward, within each other. And also flexible capacity is needed to provide optimum reserve regulation, spinning, non-spinning. Those are critical to maintain the reliability of the system. And also, flexible capacity provides support for frequency and the voltage.

Lastly, and this has been talked about a lot recently, is over-generation (ph) issue.

With renewable, we see quite different ramping than there used to be, and a lot of times we may see over-generation. And we have to be able to mitigate or absorb over-generation, so flexible capacity is important solution for that.

So if you look at the chart, this chart comes from our 2012 LTTP, now trying to study (ph). We pick up this data (ph) in the spring because this is the day we see the highest export. But if you look at the chart, it doesn't really surprise us that much if you look at load shape, the low peaks are in the evening. However, if you look at the renewable generation, you see the renewable generation picks up quickly with sunrise, and there is maximum in the middle of the day, and it goes down quickly in the evening. And in the evening and in the early morning, that's mostly from wind and other type of renewables such as geothermal and the biogas biomass. However, if you take out the import, so this is the most important part and we don't pay as much attention as we should have, the import here plays very critical role in the evening ramping. The simulation is based on assumption that all the balancing service area are dispatched jointly, optimally. That's way beyond what ISO is working on the energy and balance market. So in this study, we assume that all the resource could be dispatched, whenever needed, if it is possible to help the generation in California and in the ISO. And if we don't have so much import available, if you look in the evening hours, there is almost 10,000 megawatts ramping in about two to three hours. And at the bottom is the non-renewable generation. During the day, it stays pretty low to basically maintain the base load and the flexibility because this chart shows only the energy and it does not show the flexible capacity with reserve for ancillary service and for load following. Therefore, those resources are not only just meeting the baseload, they are also standby for the intermittence. And if we don't have imports to help in the evening, then the nonrenewable generation has to be dispatched much higher than the chart shows in order to meet the evening run.

Then, what does that mean during the day? During the day when the sun comes out and there's renewable, solar generation ramps us up, we have a lot of energy that we don't need. We cannot use it. And we have to export to somebody, or we have to curtail renewable, which is not something we would like to do. Or we have to deal with over-generation.

So this chart, if you combine the import part with the bottom part, with the nonrenewable generation, you can see the huge ramp. That's just a chart like David showed a few minutes ago. It's a huge ramp in the evening, it's not like it used to be the big ramp in the morning time; instead, the evening is much more a challenging time for us.

So how we can address those issues. One area is diversification of renewable generation. Diversification, we're talking about the technology-wise and also location. This table at the 33 percent is a base scenario of the 2012 LTPP study for 2022. This is assumptions the CPUC provided and we use energy as double capacity because there are some capacity numbers we need to verify, so we can use the capacity. But if you look here, you can see we have a very large number of wind, and we have a very small number of solar thermal. So between wind and solar, it's better to strike a balance because the wind in California mostly comes in the early morning and the evening, and during the day, wind generation ramps down, but the solar comes up. And considering the different season of our load shape and if we have a balanced combination between solar and wind, would make the operation much easier. And also between solar thermal and the solar PV, specifically solar thermal as storage, that makes the resource much more useful because the solar thermal with storage, you cannot only shift energy to the time that you need it; for example, like the chart shows that. If you can store a portion of energy in the middle of the day and use it in the evening, that can help quite a bit on the evening ramping time. And also, solar thermal with storage can provide ancillary service much more useful than with other storage. And also, in-state and out-state, as you all know, the weather changes from location to location, and the one location where you have a strong wind, and another location you might not have as much wind, and also in the eastern side of the WECC and the sun comes out sooner than the west side, but it goes down earlier than the west side, therefore, when you have it spread out, the solar generation resources, you can see much smoother generation profiles than all the resources built at a centralized location.

Then, what about the resources -- we are talking about all the type of resources, so the right mix of resources is much more effective. And the resources we are talking about is not just conventional resources, we are talking about all the demand side resources, too. For the flexible resources with fast start-up time and the ramp capability is most helpful because those type of resources, if it is a fast start, for example, like a gas turbine type of resource, they don't have to be on long, they can standby off line and when needed can be ramped up and they start to ramp quickly. And also, for the Demand Response resource, including Electric Vehicle here. In the study we did for the AB 1318, we did one scenario evaluating the effectiveness of Demand Response. Demand Response is very effective in terms of it addresses a need, even though Demand Response itself at this time does not have the capability to be ramped up or to provide spinning or regulation type of service, but it can respond quickly. So the key for Demand Response is availability and the response time because some program probably requires certain lead time in order to be deployed. But that lead time may be critical for the system operation because Demand Response, most of the time, is used to respond to the expected situation. And if we have to wait for several hours in order for the resource to respond, that might miss the window.

And storage. Storage here covers all type of storage -- battery, solar thermal with storage and pump storage, like I mentioned earlier, that the storage is critical for the next solar thermal, makes solar thermal much more effective. And for pump storage, pump storage has a much bigger volume that can store and move energy more effectively and also the hydro turbine associated with the pump storage can run pretty fast and get started really fast. And the battery in the ISO market we develop program for the battery, even though those days of battery storage is very small volume. But we made the battery capable of providing regulation service, which is very important to us because a battery can respond quickly, and the challenge is about the volume.

And lastly is about the renewable generation. So if we can make the renewable generation dispatchable, that would be a lot more effective because, as you see, the challenge must come from intermittence of the renewable generation. If we can control in a certain way like some technological people are talking about, you know, wind generation, also solar thermal with storage, those are the dispatchable, and some entities are talking about maybe with a certain level of curtailment of the renewable generation. But that would be a much more preferred on the dispatched, maybe on the side, who are talking about the wind generation and the solar thermal with storage.

Regional coordination -- so this is the area ISO is working on right now on the energy imbalance market, and also FERC Order 764 also raises more dynamic scheduling, but we are looking at more expanded capacity in those areas. And also, the new areas of reserve sharing. Currently each area (ph) has to carry their reserve by themselves, and if we can share reserve in the broader region, across balancing authority area, we can make use of reserve much more effective. And there is the more dynamic scheduling and real-time joint dispatch. We can use more flexible capacity from out of state to support the operation of us, and at the same time we can also support the operation of other balancing authority areas. And the over-generation mitigation, the chart shows that. If we have more renewable, and we don't have as much regional coordination, and we don't have as much import to rely on, then we have to dispatch much higher of the renewable generation, and then we see much larger volume of export that needs to be taken by somebody. And if we don't have the coordination between the balancing authority areas, the ISO has to be able to find a way to absorb it by itself, or to curtail renewable, otherwise our reliability will be S rated (ph). Of course, everybody understands that there is broader coordination, so energy cost will go down, it's not only just because the resource provides energy, somewhere else it will be cheaper for some certain hours of the day, certain days of the year than the California resource. If we can bring those energy in, then we can reduce the cost. And also, for the build-out and the sun, if each balancing authority area is to build the resources themselves, there could be over-build. And if we have a coordination, we can reduce the cost. So that's all my presentation today. Thank you.

COMMISSIONER MCALLISTER: Okay, thank you very much. I really appreciate your being here to represent the ISO and participate in the discussion. Just on your last slide, I had a question. Could you describe a little bit more in depth what dynamic scheduling looks like, sort of in practice, how the operators at the ISO or elsewhere interact with the marketplace in that dynamic way?

MR. LIU: First of all, the FERC Order 764, most of us import and export schedules are hourly, so that means it's fixed within the hour. And it can be changed only from one hour to the next hour, so the system changes, like I say, constantly and continuously during the hour. And if something happens and we don't have enough resources to respond, then we cannot rely on the off-site resource to help us because it's a fixed schedule of the hour, and the FERC Order 764 allows us to change the hourly schedule for most part of our schedule down to the 15 minutes schedule. So that means the schedule can be changed every 15 minutes. And if the off-site resource is a renewable, it can be changed even in the five-minute interval.

COMMISSIONER MCALLISTER: So do you then have a non -- do you have outside resources kind of on hold, you know, waiting for your call? Or are these typically sort of modifications of your existing resources, up or down?

MR. LIU: This will change the inter-resource dispatch because inter-resource (indiscernible) dispatch is in five-minute interval, so if we can bring an external flexibility, then we can change internal dispatch accordingly.

COMMISSIONER MCALLISTER: Okay, I think that makes sense. Thanks.

MS. KOROSEC: Our next speaker will be Tim Tutt from SMUD.

MR. TUTT: Good morning. Thanks for inviting me here today to speak on this topic. SMUD is very interested in this topic and you guys know about SMUD, so I'm not going to go into a lot of detail on these background slides, but we do have a publicly elected seven member governing board, which is responsible to our customer owners. And that Board has adopted some very significant and aggressive goals in relation to this topic that relate to what we're doing to try to prepare to get there.

In particular, SMUD has a goal that the Board adopted to achieve 90 percent reduction in our GHG emissions by 2050, and we have companion goals of 33 percent renewables by 2020 and 15 percent energy savings that will help us move along the path to get there.

SMUD historically has done well in renewable procurement. We've grown steadily over the last 10 years and have moved from just a third in the state to among the five large utilities to first. And today, our last year, our renewable portfolio is balanced with a variety of resources, biomass and biogas, biomethane, wind, solar, small hydro, and we're about 24 percent of our retail sales. We do believe that a portfolio is useful looking at resource potential in the future, it may not be easy to maintain that portfolio.

And here is where we get to our projected resource mix through 2050, and right now about 50 percent of our resources are from conventional and natural gas-fired power plant resources. In order to achieve our Board's 2050 goal, we're going to have to reduce that to less than 10 percent in some fashion. And that's the yellow bar at the bottom. Now, assuming that we keep our hydro resources and our 33 percent RPS in 2020, and keep that level through 2050, and assuming we get our energy efficiency savings off the top, the light green bar at the top, there still remains an energy gap that we will have to fill with some kind of zero GHG emission resources in order to achieve our Board's goal. And it would be best, of course, for purposes of system reliability to have some portion of those resources dispatchable in some fashion. So that's one of the things we're looking at. We're looking at either having additional biomethane that can be used in those conventional plants at the bottom and provide some dispatchable reliability services, or providing ways to manage the other zero GHG emissions resources that we expect to procure in the future.

If there was a 50 percent RPS that uses up or helps with some of that energy gap, SMUD does not think it's the right time to adopt a 50 percent RPS. We think there's still questions about how the system can reliably operate at that level of renewables, it has to be answered, and we're doing research to do that. But just hypothetically, if one was adopted, we still have an energy gap to achieve our own Board goals beyond that.

So one of the things we've looked at is a high variable renewable scenario case for 2030, and this is a scenario where we get to a 50 percent RPS by 2030 using a lot of wind and solar variable renewable resources. Our wind here nearly doubles from our current amount to 500 megawatts, and the solar that we would be procuring increases by about 10 times to 1,700 megawatts of solar. And we know the solar resource potential and the cost reduction potential for solar implies that there might be strong growth in that resource for most post-2020 scenarios, but the point now with that is to figure out how to keep the system reliable and flexible. I think flexibility is the word of the day here.

Just to give you an example of some of the research that we're going that shows the variation of particularly the solar resource, we installed solar installation monitors in a grid around our network, 74 squares, so that we can monitor how the geographic variability just in our service territory can help mitigate potentially some of this solar variation. And the graph that you see here shows on one day, November 8, 2012, the significant variation in the grey among each of those points, but you can also see that when you look at the red line, that variation is kind of mitigated by the geographic diversity, should we have solar installed on each of these grids. Now, it doesn't help entirely because on this particular day a huge cloud came over in mid-afternoon and completely took the solar production away, way over to the entire service territory pretty much. And if we had that 1,700 megawatts of solar that we talked about on the previous slide on line with this kind of circumstance, that would be about a 500 megawatt ramp of new resources that we'd need to make up that difference as the solar disappears.

You can also see in the yellow lines that forecasting models are not yet quite at the level where they could predict that huge drop in the afternoon. They're getting better and some of them can get close, but we're still not quite there with solar forecasting models to know that we're going to have this kind of an issue.

Now, many of you may have seen this particular video before, it's a couple years old, but I just wanted -- well, I could show it again, but it apparently is not going to work. You've seen it before, it shows the significant variation across the service territory going up and down as the day progresses and, you know, it was a quite variable day, one of the most variable days we've had, it's a very striking video when you see it. But it also shows that, if you can aggregate or if there is distributed solar around those areas, some of that variation is mitigated as you have that diversity of resource.

Now here is our 100 megawatts of feed-in tariffs that we've had installed in the last couple years, and you'd think that with 100 megawatts of feed-in tariff we'd have some diversity, and we do, a little, but you might notice that about 80 megawatts of that feed-in tariff down here in that yellow circle on the bottom and another resource that is close, is fairly tightly geographically located, it's not adversely located across our service territory at this point in time. So that can lead to issues like this because of that tight geographic diversity within our feed-in tariff, of systems on line, there was a day, April 15, 2013, where we had a ramp of 40 megawatts in 10 minutes and 60 megawatts in 40 minutes from that actual generation, and that's a ramp that's, you know, SMUD is a 3,300 megawatt system, it's something that's significant for us to understand and try to deal with. This was, in fact, the worst ramp day that I think we saw -- for two reasons: 1) obviously the degree of the ramp, but also because it was tax day.

Another example -- this is one of our feed-in tariff systems on a distribution feeder, a three megawatt system, it's on a 12 kV feeder and it potentially provides 100 percent of the minimum daytime load on that circuit. The voltage is regulated, of course, from the substation, but again on April 15th, the five-second data shows on that feeder the significant ramping up and down of that system within 30 seconds, multiple times during the day. Now, this is an issue that we'll have to deal with on a feeder basis, rather than on a system-wide basis, and so that raises the importance of having some of this flexibility and some of this control further down into the system.

So SMUD is looking at all of these grid impacts and mitigation alternatives, system effects and policies, and we're doing a lot of research on this. In addition to procurement and setting goals, we're doing a lot of research, trying to understand how we can actually get there. So we're developing better forecasting models, examining the effects as I've showed you, of geographic location, examining communications between PV inverters and our system to allow monitoring and possibly control, doing a lot of research on storage at the house, neighborhood, and system level, with electric vehicles, to look at managed charging, vehicle to home, vehicle to grid. We have done a project where we've taken en Electric Vehicle charger and tried to understand whether or not it actually would work with our signals from our distribution system on our Smart Grid, and it did. We've done Demand Response pilots, and we're setting goals for Demand Response, and we have a strategic flexible IC Engine Pilot to provide system support in a more conventional way.

So we're doing all of that and we think probably the most important integration issue is, of course, solar or a PV, and so we've developed a PV Integration Roadmap structure where we've looked at, as I said, characterization of the grid impacts, characterization of potential mitigation issues or solutions and how that works with our customers on a SMUD policy basis. And our vision for this is that our smart transmission and distribution system will be capable of integrating growing penetration in the photovoltaics while maintaining the high system reliability and operational flexibility with minimum grid integration costs. So we're trying to achieve that with a substantial amount of photovoltaics that we expect to have on our system and growing in the future.

This is an example of some of the questions that we're asking from 2013 to 2015 in this research plan. For example, at what penetrations do new distribution voltage regulation approaches need to be implemented? We're looking at all these questions. Here's another, these are mitigation issues that we're talking about, and there's a variety of them from storage to load control to advance inverters, grid design and operation, forecasting: Can Demand Response, Electric Vehicles, or thermal storage be effectively controlled to address PV variability impacts on voltage? We're asking all these questions and we're developing research projects to try to answer them and get to a point where we can manage this in the system.

So again, here are some of the questions about how we can make this work: How will PV costs reaching grid parity impact our strategy and our customer programs, our interconnection costs, grid planning, rate recovery? All of that. We see changes in this technology that are fairly disruptive to the industry, frankly.

We also have developed an integrated transmission and distribution modeling tool, and this hasn't happened before at SMUD, maybe it has at other utilities, but we're integrating transmission and distribution planning into a single model, and that enables systematic evaluation of impacts from high penetration of photovoltaics, which is expected in part to be distributed high penetration of electric vehicles, which we're seeing in our service territory, and understanding the impacts of those at the distribution level. And the most important part of this is that it allows for the transmission planners to optimize where best to maybe incent the location of PVs and Demand Response and Electric Vehicle to actually use that distributed resource and load as something that the system can react to and use. It's going to be on line this year for a future analysis for a year or so as to how this works.

We've also looked at the issue of, as was mentioned earlier, controlling this distributed resource, a smart grid communications with an advanced inverter demo. So here we were able to look at this inverter and try to understand clearly from the smart grid information what the solar resource was producing at that time, and whether we can control the impact or the amount of that solar resource through our smart grid.

One of the advantages of this approach is that it builds upon the communication network that we've already built in our service territory with our smart meters and our smart grid, so that we're able to have perhaps a low cost management solution for the resource that is not currently dispatchable. Of course, one of the disadvantages is that solar, as has been mentioned, we don't want to necessarily curtail it, it's a zero marginal cost resource, and so when you curtail it, that has an impact. We would prefer to perhaps manage that resource, to dispatch it through storage, rather than curtailment. It's kind of like nature blesses us sometimes with too much water in our hydro system to reliably make power from, and we have to spill some of that water over the dam. We never want to do that, we want to use that resource. Now, hydro comes complete with storage, solar does not at this point, but that's perhaps the goal that we shoot for is to try to understand how we take this zero marginal cost resource, add it to storage, and then have a similar situation where we try to avoid curtailing it as much as possible.

This is just an example of our storage portfolio. We're doing everything from compressed air storage research to -- you probably have heard of our Iowa Hill pumped storage project, it's a hydro project that we're potentially going to build up in our Upper American River project, a variety of different levels of storage at distribution levels, system level, and household level, different technologies, trying to understand which of these storage technologies and solutions is going to rise to the top and provide us with the ability to manage our growing renewable resources.

And then this, lastly, is just a more system-wide thing of the duck curve revisited, you've seen a picture of this already today, and probably every presentation about energy in California has this curve in the last five or six months, or longer. And you can see the familiar shape of the net load in 2013 and the net load in 2020, and what I've done is just looked at a hypothetical example of including something maybe like smart workplace EV charging in this picture.

Now, I mean, the Governor has a goal in his EV plan of 1.5 million Zero Emission Vehicles by 2025, and if we're substantially along the path to that goal in 2020 in the Electric Vehicles, and if they can be plugged in in the morning when people drive in to work, that amount of energy can mitigate some of that morning ramp, and if those vehicles then are charged enough when people drive home that they can allow them not to be plugged in right away, instead of adding to the evening peak, they can perhaps be used to reduce the evening peak. So this is just one example of how you might handle something like this. I mean, I'm sure everyone is looking at these. We either have to manage the intermittent resources through storage, or curtailment, or we have to manage the load that we're seeing, or all three, in order to provide the best solution for California as we go to 2030 and beyond. Thank you.

COMMISSIONER MCALLISTER: Thanks, Tim. Good stuff. You can always count on SMUD to set a nice example. Your last slide there had some really good examples of things you're doing and I guess, do you have a more detailed update on the smart homes or the community scale and the home scale storage systems that you're working on in that project?

MR. TUTT: Yes, Commissioner McAllister, there are appendix slides that I didn't feel like I had time to go into today --

COMMISSIONER MCALLISTER: Oh, okay, great.

MR. TUTT: -- that have some degree of information about those projects. And if you're really interested, I'm probably not the guy to ask about them, but I can certainly guide you to the right people at SMUD.

COMMISSIONER MCALLISTER: Yeah, great. Thanks very much.

CHAIRMAN WEISENMILLER: Yeah, I've got a couple questions. The first one is, what's the role of time of use rates or rate design in terms of trying to deal with the emerging system realities?

MR. TUTT: Well, certainly time of use rates, I think, are going to be useful in convincing customers, inducing or incenting customers to shift load to times where it's better managed by the system. Now, with the changes in generation profiles and variable resources, it's not entirely clear exactly when those are, too far in the future. But if we can have a time of use rate structure that adapts to how that is changing, I think that will help to manage load and bring load to the right place. Rate structure is interesting, I think that customers are going to see energy efficiency as fairly cost-effective, and solar is increasingly cost-effective. And the question is going to be how to manage the impact on other customers of certain customers taking up those investments on their own. Certainly, that's an issue that needs to be addressed and SMUD is attempting to address that issue in a way that's fair to all of our customers. So I think it's useful as an example, and California needs to look at the whole rate structure issue, in addition.

CHAIRMAN WEISENMILLER: Okay. The other thing is, given the narrow or small slice of your footprint, it would seem like one of the other tools would be looking at the energy imbalance markets.

MR. TUTT: It's possible that that would be another tool to help mitigate some of the variation of the intermittent resources. SMUD doesn't have a -- is not opposed to exploring an energy imbalance market in the West, as long as it doesn't turn into an RTO that affects the way the system is currently managed at SMUD and around the West, in more than just having an energy imbalance market in place.

CHAIRMAN WEISENMILLER: Yeah, actually our last IEPR called for studies of an energy imbalance market throughout California, along with looking at the West.

MR. TUTT: Yeah, and I believe that SMUD is looking at that in combination with some of our fellow utilities in the Northwest, we have been examining that and, as I said, not opposed if the benefits are there and it doesn't turn into an RTO.

COMMISSIONER MCALLISTER: Thanks, Tim.

CHAIRMAN WEISENMILLER: Thanks.

MS. KOROSEC: Our next speaker is Mike Webster from LADWP.

MR. WEBSTER: Good morning. My name is Mike Webster and I wanted to thank SMUD for a nice low load day today, it's very pleasant, so we appreciate you planning that for us.

So my background is I am responsible for our 20-year Integrated Resource Planning process, renewables procurement and generation -- conventional generation procurement. And prior to that experience, I was responsible for really our wholesale operations, matching load to resource on a real-time basis, and started that in 1996 and had all the fun of going through the energy market for 10 years.

So what I'd like to do is really give you some background. I think it's important to just form a basis of what LA is doing moving forward, but then I'd like to focus a little bit on the policy elements. Now, my concern about a Powerpoint presentation, and typically I don't really like these, is that it makes things seem simple, and it's not simple; execution is really key as we move forward.

So for LADWP, we have to replace 70 percent of our system over the next 15 years, a system that took 100 years to build. That is a significant undertaking from a capital, engineering, resource perspective, and of course we're doing it through a variety of ways. Now, the transformation for LA can be summarized in five different areas, one is 33 percent renewables, that's a given, we have the challenge of eliminating coal from our portfolio, some very very large projects, for example, the Navajo Power Plant, as well as the Intermountain Power Project over the course of our Integrated Resource Plan, and we have to do it in such a way that we do it in a balanced approach. And I'll get to that in a second.

We also have the eliminate once-through cooling, so our coastal power plants are absolutely critical to managing our transmission grid, so we need our coastal power plant. So we need to get off ocean water cooling, that's for us, that's our once-through cooling, there's ocean water cooling, and we're doing so in a very planned way. And we are currently at 10 percent energy efficiency which is a fourth cornerstone of our transformation and we're looking at ways, can we make that higher than 10 percent? And we're going through a maximum potential study that's ongoing right now, and by the end of the year we hope to know more whether we can push that and beyond.

And then for us, we also have to keep

mindful that we have a very very old transmission and distribution infrastructure, and we have to make sure we plan the capital so we can replace that infrastructure, so that we don't have transformers blowing and overloading circuits, etc., because our system is relatively old. Now, this is really to show that we can't take one item and just plug it in, it all has to be integrated to work together, so as we look at renewables, we want to do it in such a way that, when we change out our once-through cooling, can we do it such that we integrate renewables more effectively. Or, if we eliminate coal, how can we do it with renewables, gas-fired generation, energy efficiency, and pull all of that together. For us, every single bolt on of a strategy must be integrated in the whole. Now, this is the right group, this is a planning group, we all understand that, but there are other policy makers that don't quite understand that, when you just say, "Well, we're going to do distributed generation," that it really has to be integrated into the whole, and we have to really plan the whole system to be able to respond to that. And then a concrete example, for example, our Navajo

Generating Station, which we are targeting to replace by 2015, the first thing we're going to do is energy efficiency, let's deploy energy efficiency and then wrap around that the renewables, and then lastly, then we add the combined cycle generation to supplement that. So, again, it's trying to bring all the portfolios together.

In our future, our Integrated Resource Plan shows no coal on the left, more coal on the left, and then no coal on the right, you'll see the energy efficiency, maybe we can grow that pie a bit; renewables, we'll talk about from a policy perspective, and then quite a bit of natural gas. So that is really our future. Now, the results is that we're going to have a 60 percent reduction in greenhouse gas emissions from 1990 level, just doing what we've already planned to do, moving forward over the course -- and we do a 20-year Integrated Resource Plan, so we go out to 2032, we'll do 2033 this year, etc.

So the only reason I put this slide up is to really say that, if we're going to start looking at increased levels of renewables, we need to be able to also have quick start units that come on line in the right pace. This is our quick start unit strategy and it is the tightest possible strategy for us to replace our conventional boilers with new gas turbines, with new combined cycle, because it supports our transmission grid, we kind of liken this to -- it's like changing the engine on a 747 while it's still flying; we cannot just take out units and just put a new unit in again, we actually have to build a unit, get it operational, take the next unit out, and do that sequentially. So this is the tightest possible schedule we can deploy to get our quick start units operating and you'll see the plan really takes us all the way up through about 2029.

And so then, diving down a little bit into renewables, and I'll try not to blind anyone with this, but our initial deployment has been wind, but our future you'll see quite a bit of solar starting to develop, we just started our solar procurement, we have construction starting on a 250 megawatt plant, we have construction starting on a 200 megawatt plant, those are just now starting to be built as we move forward, but we see solar, especially local solar, really being our growth in the 33 percent, and then we are looking at geothermal, we have a couple of contracts that we've signed, we're looking at developing some land for geothermal, and so we do see geothermal growing in the future. And then you see our energy efficiency as it grows. So this is our strategy in our current Integrated Resource Plan.

So what we wanted to do is show you just L.A.'s perspective. You've seen SMUD's perspective, you've seen CAISO's perspective, as we look at the future and 33 percent, now, some people see a cute mallard in there, I don't. We haven't named this animal yet, but this is the beast that we're really trying to manage, and so here on an April day, this is the solar and the over-penetration of solar that we're going to have to need to dispatch that, or do something with that energy. So for us, it's those March, April, early June time periods where increased levels of solar really creates challenges for our system, and at the same time we also have to have the capacity to back up the transmission grid, so we can't just shut off all of our conventional generation which has rotating mass and inertia moving forward.

So some of the policy elements that we think need to be addressed: I think it's a given that nimble gas and hydro generation is going to be really important for the future. You've heard this before, Demand Response programs, but these are the Demand Response programs where you can really use it for regulation. So the technology needs to be deployed, the contracting process needs to be deployed and, quite frankly, how do you integrate all that into your grid operations when you could have thousands of customers working with you so that you can actually manage that and integrate renewables and have that quick response to implement those variable energy resources.

We think that storage is a great idea. The key for us, though, is it's got to be utility scale, it's got to be proven that it will actually work, and it really needs to be cost-effective. Maybe it's better to back off the solar for a few days a year, it really depends on what the cost/breakeven response is.

And then, lastly, we think that Electric Vehicles are going to have a significant impact on our system. Now, the conventional thinking is Electric Vehicles, they're going to be charged at night, again, flatten that load curve. And we're starting to see, well, how can Electric Vehicles actually be promoted to help with some of the integration? So, for example, during those April days, could we put energy on sale and say, "Please come charge your electric vehicle during peak on Sunday, please absorb it for us?" And is there a way to elicit that sort of response from customers where they actually kind of see what's projected in some of the pricing?

We need the ability to control the variable energy resources. That's been talked about a lot, our output and ramp. But we also have to make sure that we can control it such that we can handle voltage regulation and some of the frequency, and we also recognize that we're moving towards more and more distributed generation, you know, literally thousands now of power plants locally. So how do you bring the information of thousands of power plants in the grid operations, have them make decisions, and then control those power plants to control the voltage, that control the frequency, and to control the ramp, and the loads? The significance of that challenge should not be understated, it will be significant. Grid operators today have a huge challenge integrating the systems they have, whether it's CAISO or LADWP, so we need to think through those information technology requirements and build that for the future.

We are becoming more concerned as we look at our studies about the voltage stability of the high voltage transmission system. We are starting to see that, with more penetration of wind and solar, is that the voltage control because there's not the rotating mass behind it, pushing the energy through, it's going to become much more challenging in the future. So as we eliminate our coal plants, that's pretty significant in how we're going to manage that in the future. So I think that a focus on the transmission grid and transmission stability will be critical. And then, also on the distribution grid, is how is, you know, when we have overcast days, locally, and that overcast starts to break up, when we're starting to get this solar change, it's going to create voltage instability on the distribution grid, so how can we use Demand Response in relation to other technologies to integrate that even from a dispatched perspective.

So going forward, we would like to see much more flexibility and diversity in the renewables portfolio. I think California set out a pretty clear standard, California Bucket 1, a little bit of out of California, Bucket 2, and then Bucket 3. But we think moving forward for increased renewables, we're going to need more in-state biogas and more out-of-state biogas, so we can use biogas to fuel those quick start units to back up wind and solar.

We also think that, if we're going to go to higher levels of renewables, we really need to look seriously at out-of-state resources. There's some tremendous resources out-of-state for wind, especially. And so those are the types of things we need to consider as a policy before we set higher levels, and then the real focus needs to be on what gives us the greatest greenhouse gas reductions moving forward. Another policy element is that we really need to look at the rate impacts, and so for us, is that the rate impacts are really starting to look at not just the extra cost of the renewables, but it's the renewables and everything else that it takes to actually integrate those in the system, the dispatch, the control systems, grid operations. And I think that is very important to inform any policy discussions moving forward. And whatever we do with renewables, I think, needs to be balanced with other types of greenhouse gas emission reductions because there may be more cost-effective reductions out there besides just increased renewables.

And then, lastly, we really need better predictive technologies. We need the ability -- and I think Tim went over this a little bit -- is that the ability to track cloud movement, know how quickly that cloud is going to hit our solar facilities, to see the size of that cloud, and measure that impact, because if we can just get a 10-minute lead time and take corrective actions, we can dispatch our system to be ready for those fluctuations in the system. So a lot of research needs to be done here in real-time weather forecasting.

And so three last thoughts, one is we are doing a lot, and we need to learn about the impact of what we're already doing, that's critical. I think SMUD shared some information and we'd love to learn more about what SMUD is doing and what CAISO is doing, but as a utility industry, we really need to understand the impacts of what we already have. Then, we think that the industry really needs to work together on targeted studies to say "this element is critical," so, for example, whether it's transmission stability, or distribution voltage, or whatever those studies are, we need to really look at those studies before we inform policy. And lastly, we really want to make sure that what we're doing is we're meeting greenhouse gas emission reduction goals in the most logical, cost-effective strategy moving forward.

And I only show this slide, this last slide, so that if anyone is interested in our Integrated Resource Plan, we've been very public about it, so they can actually look for it on the Web, we're going for a 2013 Update, not a lot of change, it's usually updates of assumption, but 2014, I'm sensing, will be significantly different assumption sets, different modeling, different scenarios as we move to 2014, which we're going to start that process actually quite soon. So thank you for your time, appreciate it.

COMMISSIONER MCALLISTER: Thank you very much. I'll just say last year I was really happy to see the quite substantial IRP slam down on my desk, and --

MR. WEBSTER: It wasn't thrown at you, I hope.

COMMISSIONER MCALLISTER: No, no, no, it didn't do any damage. But I was happy to see DWP really taking that IRP approach again and I think it's a good development, there are lots of -- yeah, some rigor in that, as needed, an IRP enables that. And it's really great to see that DWP is hitting these issues head on. Having said that, I guess I have just a couple of questions. On the Clean Energy Future, the sort of projection of 60 percent below 1990 levels by 2025, I guess could you sort of put that in perspective where, given that DWP is on the carbon intensive and, at the moment, of the spectrum of utilities in the state, where does that leave you sort of in 2025 with respect to the other utilities if, indeed, all the, you know, you do get to the 60 percent below 1990 levels by 2025? Where does that sort of put you in the pecking order?

MR. WEBSTER: You know, I don't have the answer to that because I don't know where all the other utilities are, but I will say that, to get to 2025, the criticality of that is to get off of the Navajo Coal Power Plant and then Intermountain by 2025, which at a minimum will be two years earlier than the 2027 requirement, so we're trying to really be aggressive. Navajo is 2019, so we're really trying to get off four years early and Intermountain two years early.

COMMISSIONER MCALLISTER: Yeah. Okay. If we can do a little follow-up on that, I just want to make sure sort of where things are in the grand scheme of things, but clearly that's a big lift and really appreciate your and Ron Nichols' effort on that.

A couple slides later, I just can't help but notice the increasing renewable energy and energy efficiency stuff, that it seems like across the board you've got some pretty major inflection points basically starting right now, and so I just want to point that out, you know, it's so clear that business as usual just is not going to get us there, and I know the utilities made some great hires in the last couple of years, and are really getting its ducks in a row, but certainly all the colors of wedges here, but in particular the solar wedge and the EE wedge get a lot bigger really fast, so I don't want to underestimate the challenge of that, and just kind of want to call it out as a big lift on your part. But any additional comments you have on those two things would be interesting.

MR. WEBSTER: So on the solar lift, you know, that represents about 1,200 megawatts of additional solar and we're trying to look at our system and say, "Well, when do we get to the point where integration is going to be very difficult with existing technologies, with what we already have?" We would love to see solar thermal as part of that mix. The problem is solar thermal is just too darn expensive, and we need to get solar thermal to where it makes more sense because right now, quite frankly, we can do PV and back it up with gas generation much more cost-effectively than the solar thermal. So there needs to be real development to get those costs down in the future. And you'll see that the geothermal, I think there's more opportunity now that the transmission is starting to be built into the Imperial District area, that's going to be very helpful. We're looking at developing some of our lands. There's additional geothermal down there, and so some of that baseload will help. But I think in the future what we would like to see is we'd like to see more wind development and I just don't see that, quite frankly, happening in a significant way in California. I think it's going to be development from out of state, where if we're going to get the biggest lift in wind, and you don't see that in our current Integrated Resource Plan moving forward. And I think that you're going to see -- I would hope that we can actually add some additional biogas in the future once a little bit of that gets settled out in the state and we actually can see some pipe-like haul (ph) in the state. To us, that's really critical to fuel conventional generation, quickstart units with the biogas.

COMMISSIONER MCALLISTER: Have you done some studies on inventory, sustainability of that inventory? I think that's obviously an issue going forward, but where you're going to get the biogas, and is it truly sustainable in-state, and all that good stuff.

MR. WEBSTER: We haven't done our own studies, we've been following some of the studies, and while I think there's probably a little bit of a bubble right now from an out-of-state perspective, you know, we are trying to move to less waste, and that's going to diminish over time, but we think that in California there's still substantial development because that is not being fully utilized for a generation in California. It's too costly right now to put generators right at the landfill sites and I think that there's enough smaller landfills out there that could be very productive from a pipeline quality perspective, to get into the pipelines so that all the utilities can make use of it.

COMMISSIONER MCALLISTER: Okay, so that depends on pretty serious infrastructure investments in the pipelines and other things.

MR. WEBSTER: Not so much the pipeline side of things, but certainly getting gas cleanup technologies and would that be allowed in California, and they're working on that.

COMMISSIONER MCALLISTER: Okay, got it. Thanks for the clarification. And then finally, I'm wondering what is DWP doing on Demand Response and kind of how does that fit in this wedge graph that does out to 2025? Maybe it's within energy efficiency, or maybe it's outside the --

MR. WEBSTER: It's outside of energy efficiency, it is a study that we just started, I'm responsible for that, as well, is that by the end of this year we brought in the consultants to try to figure out what's been working in California to see what would work for our system because our customer mix is a little different than some of the other utilities, we don't quite have as much industrial, a lot more commercial. So what would work from a two-hour perspective a one-hour perspective, and a 10-minute perspective. So I think what you'll see by February of this next year is you're going to see kind of an integrated resource type plan for Demand Response, and we have a 10-year plan to bring in 500 megawatts of Demand Response, we're not sure that's achievable, but we've put it into our Integrated Resource Plan. But we're really trying to build the tactical game plan to say, well, how do we get the first piece, how do we get the second, how do we get the third and fourth? So again, it's to focus on that execution, so it's not just a Powerpoint and we're just going to achieve it somehow, but it's an executable document that will show what we can achieve, what resource it's going to take to get there, and so we've dedicated a group just to develop that sort of 10-year look ahead for Demand Response. So we're excited about having that in February, there will be significant public comment, I think, on that. We'll treat it just like the Integrated Resource Plan, we'll bring stakeholders in and ask what they think, bring customers in, and that will be one of those things that every year we just really look at tuning up as we continue to execute. But we think it's critical to Demand Response for the next 10 years, absolutely critical.

COMMISSIONER MCALLISTER: Well, thanks very much. I mean, I think we all recognize that it's unique -- your service territory is unique to the state and you do a lot of things really in that context, and we appreciate your increasingly leading by example on that front, despite all the constraints of the particular area you're in. So thanks for being here today. Chair Weisenmiller.

CHAIRMAN WEISENMILLER: Yeah, a couple questions. One is probably a word of caution to you and SMUD, is that one of the longer term issues we're going to deal with in the biogas area is the tradeoff between using it for power, but using it for transportation fuel. And you know, transportation fuel, there are pretty heavy lifts there, you know, certainly we're looking at electrification, we're looking at hydrogen, certainly biofuels could be a part of that mix as we go forward, and so, again, that's one of big policy choices for California is where does that go.

I think certainly the other question for you is, again, similar to Tim, you know, is historically I've used the metaphor at times that there's more or less a moat between LADWP and Edison, and we need to have better integration to deal with issues, so certainly encourage more interconnection, you know, again, investigations with things like EIN to basic EIN to figure out how we can, as a state, deal with these challenges. And obviously one of the assets you have is Castaic, and so in terms of modernizing it, I remember years and years ago I got a settlement between you and Edison on some litigation, I was working for LADWP at that point, as the City Attorney, and coming out of that, Edison was actually able to use part of Castaic, obviously for a cost, you know, getting some payment back to LADWP. But again, that's such a huge resource and I know it probably needs some degree of modernization in terms of variable speed, motors and everything else, but that could really be a credible tool for Southern California in terms of trying to integrate renewables.

MR. WEBSTER: So I have two comments, if you don't mind.

CHAIRMAN WEISENMILLER: Sure.

MR. WEBSTER: Is the first on the biogas is that, you know, I think that instead of Government picking where the biogas is deployed, is to let the market actually because, you know, if utilities can use biogas, as well as the transportation sector, and the pricing will allow that biogas to be used in the right resource, so if they're willing to pay more, then we're going to let it go that way; if we're willing to pay more, it's going to come -- but that competition, I think, is really important moving forward. The second is on Castaic, and I think I had it in my slide deck, I missed the point, but really what we see is that we would really like to see a much more robust market and I think SMUD alluded to this, I think the CAISO alluded to this, but if there's a robust market for regulation services and balanced energy, you see, then the technologies that we have, that we're really using to integrate our renewables, if we're long, we want to share those renewables. We want to serve our customer load in the most cost-effective manner possible and then everything else we want to be able to share. So if there's a bright market and we can share those resources, that's what we want to see, whether it's in California, or even out of state, is share all of our resources. And the market is what's going to really drive that, if we have the right market structure.

CHAIRMAN WEISENMILLER: That's great.

Actually, the other thing I was going to say on the storage area, again to both, is that when you read some of the documents on the German experience, particularly one of their think tanks, Agora, has looked at a lot of issues they're facing there which, you know, it looks like we're getting to the same place. They're much much more optimistic on thermal storage than batteries and other stuff, and so one of the things that we're really trying to do looking at future thermal plants is to make sure thermal storage is built in.

MR. WEBSTER: Uh-huh.

CHAIRMAN WEISENMILLER: As a way of, again, dealing with the variable nature of stuff and just that there's more and more of a pressure on plants in terms of the minimum load conditions, you know, to basically figure out some way to deal with over-generation might be thermal storage at some other thermal resources.

MR. WEBSTER: And we would agree if it's cost-effective and utility scale and it has to just work, and so we think that it's worth the investment to continue to develop energy storage technologies to where they're really viable. I just think we're quite a ways away from that.

CHAIRMAN WEISENMILLER: Yeah, and I guess the last observation I was going to note, it's really good to see that you're looking at additional geothermal. I mean, that's obviously a really important resource for California, but it's becoming more challenged as some of the other utilities basically are finding themselves baseload long and refusing to sign any new contracts for geothermal, even with existing projects.

MR. WEBSTER: Then they should call me.

CHAIRMAN WEISENMILLER: Good.

COMMISSIONER MCALLISTER: Thanks very much.

MS. KOROSEC: All right, we're shifting to our next slot on the agenda, which is On the Way to 2050. And our first speaker is Jeffrey Greenblatt.

MR. GREENBLATT: Can people hear me okay? Thanks for the opportunity to speak. I just want to say I work for Lawrence Berkeley National Lab, but I was heavily involved in the CCST study, so I'll be presenting that study's results, but some of the comments will be my own.

So I was asked to give an overview of how the results of this study that was done a couple of years ago and really looked at 2050, how it may have some helpful insights for the interim 2030 timeframe. But just in case people aren't familiar with the results, I'm going to very quickly go over that. First, to say that the study actually came out in several sections, there was the Summary Report here on the upper left that was released in 2011, and then over the last 18 months or so we've come out with some more detailed reports on different sectors, and we're now finished, there's a total of seven publications all available online at CCST.US.

So our focus was on trying to figure out how one would technically reach the 2050 target of 80 percent below 1990 levels across all sectors, not just electricity. What we found to be a useful graphical way of picturing this is kind of breaking all the different activities available to us as a state into four basic activities that have an effect on one or another of the dimensions shown here in sort of a total greenhouse gas emissions diagram being indicated by the area where we have demand on the X axis and greenhouse gas intensity on the Y axis. And one important distinction is that we've divided our demand into two sections, fuels and electricity, because there's an important interplay between shifting from fuels to electricity as a way of reducing overall greenhouse gas emissions, but this box shows what might happen under a business as usual scenario in 2050. We're currently at roughly half the submissions of CO_2 equivalents, so it would be a big increase. Of course, some of the things that will help reduce emissions are now underway that were not included in this baseline a couple years ago.

But obviously the first is to reduce the demand for both fuels and electricity as much as possible across all sectors, and in our modeling we assume pretty robust levels of efficiency improvement, sort of on the order of 40 to 50 percent over a baseline by 2050. Of course, it varies sector to sector.

And then the second element is electrification and here we look not just at vehicles, which has been mentioned in several of the remarks earlier today, but also which has as very important role in reducing demand for hydrocarbon fuels, but also looking at building heat and industrial heat opportunities for electrification where it makes sense from a cost perspective and from an efficiency perspective because the use of things such as focused electrical heating or heat pumps can be more efficient than even the best combustion-based technology. So anyway, this continues to reduce the demand on fuels, but at the expense of increasing the demand for electricity.

And then finally, once we had put together several scenarios based on looking at the demand side, we then looked at the opportunities for reduced greenhouse gas intensity, both for fuels and electricity. And this is a schematic diagram, there are more opportunities for reducing the greenhouse gas intensity of electricity, so it's sort of this side of the box would be lower, but we didn't want to make that distinction for the cartoon's purpose. In any case, combining all of these around different sectors results in a target fairly close to the 2050 goal, although we didn't quite meet that in our base case scenario. And one of the biggest take homes, which I'll summarize in the next slide, is that we didn't think that we could get all the way toward the 2050 target using the technologies that were off the shelf or in imminent development, but rather getting to roughly twice the 2050 goal by introducing all of these actions that I've summarized over the last couple of slides.

There's obviously a lot of uncertainty here in our assumptions; this number might be closer to the 85 or so million tons, but the point is that it's probably going to be an overshoot without continued technology development in a few key areas, which I'll summarize in the next slide.

So what I'm going to do is kind of give you the basic conclusions of our 2050 study, and then in the final slide show you how that suggests some things that the state needs to think about for 2030, again, looking at electricity, but also other sectors that impinge on electricity development.

So the basic lessons for the 2050 picture is that, even if we assume -- this is sort of a summary of what I've just said -- but efficiency, very serious efficiency improvements in all sectors, a lot of electrification both within the transportation sector and in buildings, very decarbonized electricity system, which pays attention to the residual emissions needed to balance a renewables heavy load, and very large amounts of low carbon biofuels. We're unlikely to get all the way to the 80 percent level without some further developments. And so this is sort of the menu of things that need to be on the development and time horizon, as well, by 2050.

Lower or zero carbon load balancing strategies -- we've talked about some of these such as electricity storage and Demand Response, also using lower carbon natural gas if that's going to be continued to be the preferable load balancing technology. We're going to need much larger supplies of low carbon fuels and that's going to greatly reduce the carbon intensity across all sectors.

We didn't include this in the base case, but something else that would really help is if we moved more strongly to a hydrogen economy as an alternative to Electric Vehicles. I know it's not on the near term planning horizon, but it's something else that could help reduce the carbon footprint and bears keeping in mind.

And then we also called out some things including negative emissions, that is, combining biofuels or biomass generation with carbon sequestration to further lower the carbon footprint, as well as looking at other ways to reduce demand, and I don't mean fewer people like, you know, sort of preventing people from moving to California, but it may be that the population projections will change and that may have a big impact on our demand growth, also where those people live could have a big impact on how much energy they consume. And there's a number of other technology developments that have been highlighted in our reports that welcome to discuss if people have questions.

And another thing that was left off of our scenario, but wound up being a rather large piece of total emissions in 2050 is the non-energy sector, things like F gases and emissions from agriculture, landfills, etc. also need to be looked at on the same timeline because they're significant emissions by the time you're getting down to the levels of an 80 percent reduction.

So I took a fresh look at our conclusions for this meeting and thought about what would really be most useful to say for 2030, and this is what I came up with. And these, I just want to say once more, these are my own opinions, but I hope you will find them useful. First is, you know, the RPS mechanism is a very powerful one, it's increasing the amount of renewables in the system, it looks like it's a useful mechanism for continuing to increase the amount of renewables, both statewide and regionally, but I wonder whether there might be a way of helping other low carbon technologies that are not actually renewables get some foothold, as well, and I know that some people who were in the CCS industry have been asking for a mechanism of this kind, so it's something to consider, that CCS may become an important technology post-2030, Carbon Capture and Sequestration.

Another thing to emphasize is that, while natural gas is an excellent bridge fuel to lowering the overall carbon impact of the electricity sector, it's not really a very effective endpoint because there will be significant emissions post-2030 from the burning of natural gas that may make it very difficult to meet our statewide targets, so we need to think about ways of slowly phasing that out as we move toward the 2050 timeframe.

Also, I believe that while the electricity goals sort of up to 2030 are looking fairly aggressive, we're going to have to think about continuing to increase the amount of Electric Vehicles, both personal vehicles and other sectors in order to keep that going because this is such an important component of reducing fuel demand and increasing potential flexibility in the electricity system from what's been discussed. So thinking about how we can continue to increase that requirement.

And I want to just bring this up again, but building electrification is something that's kind of not on the radar right now, and I think should be, I think there might be some cost-effective opportunities for bringing that more into the portfolio.

And I'm just going to briefly say that I don't really have anything to say other than to raise the question of are we on target to meeting our ambitious and CPUC efficiency targets, that we sort of assume the CEF study and, if not, what are our alternatives if we can't continue to increase the levels of efficiency improvement? Are we going to have to turn to an alternate strategy as we move toward 2030 and beyond? Likewise, the amounts of biofuel that are going to be required to get to the 2050 target are going to be very very substantial, I think really taxing both the in-state and potential out-of-state resources for biomass. And I don't think anyone has some good answers other than it's an issue and we need to think about whether the resource is there, and what the best mechanism to push biofuels into the state would be.

And I'll finally flag some recent work that some of us have been looking at and that there may be some potential changes happening in the transportation sector that could be quite significant, not likely, let's say, but vehicle automation in particular seems to have some potential efficiency improvements and could herald some lifestyle changes. And it's very early stage, but it's the kind of thing that we at LBL try to look at and at some point he state may want to consider these kinds of unexpected changes, as well.

Those are my comments. So I'm happy to answer questions.

COMMISSIONER MCALLISTER: Great. Thank you very much. I am familiar with the study and your work, so really appreciate that. Your insights are very thought provoking; in particular, let's see, bullet 5, you know, that's a great question and we're working actively on trying to figure out how to really get into the existing building stock at much greater scale, and so I think some scenarios along those lines would be very helpful to figure out what that looks like as far as goal setting for the existing building stock, what we would need to accomplish in order to fit the pieces together to get there. And your second part of your question, if that doesn't happen, then what? And I was a little interested that storage and Demand Response are not in your base case, and so maybe you could talk about the decision.

MR. GREENBLATT: Sure. To clarify, actually, there was some storage and Demand Response in our base case, but we found it difficult given that it was not an economically driven study, but rather a technical feasibility study that obviously paid some attention to cost, but could not do a thorough cost evaluation, that we had to punt on that, and so we assume some.

COMMISSIONER MCALLISTER: Okay, thanks. I think, you know, where it gets fuzzy is where you have cutting edge technology where you have sort of fully unproven -- you get up there in the market and you're not sure what's really going to work, and so I think having these scenarios is really helpful beforehand, and as we go into these aggressive -- more aggressive policies to try to get the increasingly not so low hanging fruit because we're going to be at the margin, and so we really have to figure out, you know, the boundary and how it evolves, and to enable questions going forward at each new frontier, and so I feel like working on the various scenarios, fleshing them out more deeply, definitely is a good thing to be doing going forward. So, Chair Weisenmiller?

CHAIRMAN WEISENMILLER: Yeah, I had a few observations. First -- actually, there seems to be a lot of progress now on CCS. You know, when the Governor and I were in China, they have an operating carbon capture plant, although basically they're using it for carbonation of drinks, you know, but anyway it's working right now, and there's a number of potential projects popping up around California. The *New York Times* had a pretty good article on Summit's project in Texas on CCS. In terms of your observation on electrification of buildings, actually, the thing which I'm really pushing is not that, you know, I find it thermodynamically offensive, although heat pumps could be interesting, but really solar -- why not solar thermal for space and water? Why not solar thermal for industrial process, heat? Certainly if you look at the advances at U.C. Merced, they're making a lot of progress on industrial process heat, they're making a lot of advances on cooling. So, again, it may be we'll have to do something, but at least it seems like reaching out on the renewable front first is more coherent on electrifying and enhancing some of the issues. I think, as Andrew said, I tend to say if we can't really crack the existing buildings, particularly the rental sections, you know, it's going to be very very hard to meet the energy efficiency goals, I mean, that's just period.

I think in terms of transportation, actually at this point the auto industry seems to be much more optimistic on hydrogen or fuel cells, frankly, than batteries. And so if I can figure out how to get about 70 hydrogen fueling stations out throughout the state and in the right locations, the auto industry -- all the majors have been committing they will roll out fuel cell vehicles in California at 2015 to 2017, period. And so, again, since transportation is such a heavy lift, and such a key part of our economy in terms of goods movement, the more we can -- as you said -- the biofuel stretch is so huge, if we can really get batteries and fuel cells and biofuels, it's a lot more of a viable mix than just one or maybe two out of the three.

MR. GREENBLATT: That's right, I agree. That would make me sleep better at night knowing there were multiple strategies to reduce fossil demand.

COMMISSIONER MCALLISTER: I want to pile on, actually, to what Chair Weisenmiller said with regard to solar thermal, I mean, that's just something I've been working on for a long long time. And, you know, since the '70s, there's been sort of up and down experience with solar thermal and the various applications, you know, residential and commercial pools, that kind of stuff that could if adopted widely avoid a lot of natural gas combustion. And it's a market issue of getting it out there and kind of getting the pipeline full enough and getting the cost down a bit. And I think it highlights the difference between personal economics and, well, it sort of highlights the difficulties between fuels with respect to the sort of economics of it, right? I mean, natural gas is cheap right now, so it's not driving that kind of investment from the private sector. And it also, well, there's also sort of a larger infrastructure issue, as well, who makes the investment in shifting over to some of these newer technologies. So, again, I think having the ability to fairly nimbly run scenarios and sort of bounce policy options off of a model like this is going to be helpful going forward. So thanks for that.

MR. GREENBLATT: Sure.

CHAIRMAN WEISENMILLER: Yeah, thanks.

MR. GREENBLATT: Okay, you're welcome. My pleasure.

MS. KOROSEC: Our final speaker this morning is Jimmy Nelson from U.C. Berkeley.

MR. NELSON: So I'd like to thank the Commission for inviting us here today. I know I've put a lot of work into kind of envisioning what the future of the energy system in the West and in California could become over the last four and a half years that I've been working on my Ph.D. -- you'll notice the words "graduating Ph.D. student" on the slides. And I've done so with my colleagues, Ana Mileva and Josiah Johnston --

CHAIRMAN WEISENMILLER: Congratulations.

MR. NELSON: -- thank you.

COMMISSIONER MCALLISTER: We both know how difficult that is.

MR. NELSON: Certainly, certainly. And under Professor Dan Kammen, who wasn't able to be here today. So I've been working on this model called the SWITCH model for the past four and a half years, and what it attempts to do is simultaneously plan the capacity of generation transmission and storage assets simultaneously, so this is of course in an effort to reduce costs, while getting to greenhouse gas and renewable energy targets by trying to figure out what storage transmission and generation we should deploy, as well as, of course, efficiency to end up meeting our goals cost-effectively.

So to frame the problem, power systems with high fractions of wind and solar really pose some serious problems to existing capacity planning models. So we need to have, in capacity planning models, the ability to trade off between different sources of flexibility, namely transmission, gas storage, geographic diversity, and, in a long term planning framework, also things like efficiency, so build the efficiency that best matches the load profile you're thinking of, but then the load profile you're thinking of might change, depending on what efficiency you would build. So how do we make kind of self-consistent tradeoffs with respect to all these different things that we could install in the 2030 timeframe, and even looking out further towards 2050. And how do we do so at least cost and in the context of carbon and renewable energy targets. I really like that slide from the gentleman at LADWP in which, you know, there are all the circles of the different kind of components of the problem, and then there was the integration aspect of how do we stitch all this stuff together, and they're all very interdependent. And so we try to look at a lot of those interdependencies in a modeling framework. It's evident to everyone in this room that both spatial and temporal aspects of planning will become increasingly important over time.

So to go into a little bit of detail about what we used SWITCH to look at, SWITCH, as a caveat, is used here as a scenario analysis tool. It should be understood that our results are not projections, they are just looking at ways the energy system could possibly evolve on a least cost basis, subject to it having to meet a lot of demands, which I'll go into later.

And to do this, the long run investment framework is very fundamental, so we're going to be installing a lot of new capacity and generation transmission storage, energy efficiency, Demand Response, all these things, in the next 20 to 40 years. And so we therefore use kind of a pre-market framework. We're consequently not able to say a lot about what our investment plans would exactly function in the market, but the guiding principle is to minimize the whole cost to the power system, while also meeting reliability requirements, long term policy requirements, renewable requirements, and so on.

We take a system-wide approach across the whole WECC power system and used many different time scales from a parameterization of these sub-hourly needs for balancing, all the way up to the decadal timescale of policy goals. And SWITCH can provide valuable insights to the power system with respect to future carbon emissions, what the generation sources might be from kind of different scenarios going out in the future, how we can stitch together short and long term policy goals to make them self-consistent, and estimates of the possible costs that any given scenario might end up resulting in.

So one kind of detailed slide about the tool, the SWITCH WECC Power System Planning Tool, its objective function is to meet the net present cost of demand in all simulated hours in all investment periods. Investment periods are these kind of blocky entities that we model going out into the future.

In the results I'm going to show, we've modeled 2020, 2030, 2040, and 2050 as kind of distinct units in which you have to meet certain power system requirements. And you have to do so, as I mentioned before, subject to carbon policy, renewable policy, linear as to operational constraints, resource constraints, etc., the things that you want your power system to do for you.

And we use 144 distinct hours simulated in each period, these are hours in which we have the capacity factors for wind and solar matched to that of future projected loads, so we include kind of all the interdependencies between when the wind is blowing, when the sun is shining, and when people are wanting to consume electricity.

We divide up the WECC, the Western North American Power System, shown in red, into 50 load areas within which demand must be met in all of those simulated hours, and between which transmission is done. So these we consider kind of larger transmission paths, rather than a detailed network model; and the reason for that is that the detailed network models, while very important, wouldn't capture kind of a lot of the long term dynamics of the power system, they'd be kind of a necessary post-optimization check to make sure everything was working exactly as planned. We include thousands of possible wind and solar projects and all the existing generators in WECC.

So for this study, I'm describing a study that's more or less a follow-up to what Jeff was talking about, the CEF Study. In their study, and also Jim Williams' study of the California Energy System getting to 2050 greenhouse goals, it was really highlighted that the electricity sector was likely to be pivotal in reaching those 2050 goals. And so our modeling team took a deeper dive into the electricity system and we looked at kind of relatively deep carbon reductions in the 2050 timeframe, but today we were asked to focus on 2030, so the carbon reductions that I'm going to show for different power system assume a WECC-wide carbon reduction of 30 percent relative to 1990, so 70 percent of 1990 levels. And they're of course headed down to a much deeper reduction level, as Jeff mentioned, that the decarbonization of electricity might be easier than for other sources, especially transportation. So we might want to pick a target that is a little lower for electricity, in terms of emissions, than other sectors.

So one thing to note, as we take the kind of long term view of things in our work, and I think folks think that it's going to be relatively hard to get California to decarbonize if it's not in the context of WECC or the United States that's also decarbonizing, so that might not be, you know, a reality by say 2020, but by 2030, 2040, 2050, it gets increasingly harder if we're going it alone, politically, kind of the physics of it all, everything.

So we assume in this study a cap on carbon emissions in WECC and that means there's implicitly tradable carbon permits between different states and, so, take that as a caveat, we know it's not the current state of things, but we kind of hope it is in the future and maybe the Obama Administration will help to make it so.

So I said we were going to take a deeper dive into the electricity sector, and here is kind of the first of those deeper dive plots. So what I'm showing here is the shift in the demand profile after doing -- oh, there is a Powerpoint Mac to PC problem -- so a shift -- I'll highlight that in a second -- we show a shift in demand from efficiency and also from the electric heating and electric vehicle demand sectors. This plot is supposed to have the light blue line and the dark blue line below it, actually at the zero demand mark for WECC, I'm sorry it doesn't end up looking like it should; the point is we're doing drastic energy efficiency in these studies, and that's kind of the idea that we're headed to 2050, you've got to start deep efficiency and electrification early, otherwise we're likely to miss the carbon targets we've set out in the 2050 timeframe. And the biggest story by 2030 is these deep energy efficiency cuts, which are not shown very well in this picture, but I think they keep demand roughly flat, perhaps even turned down a little bit in the 2050 timeframe, I think it's roughly flat.

So last slide before I move on to some results of our recent study, the base scenario that we assume has a number of characteristics, so new biomass is assumed to be excluded from electric power, that solid biomass we actually include landfill gas, we give it to the electricity sector because it might be relatively easy to use there. We exclude new nuclear and we keep solar costs and other projected costs by this kind of what's becoming the semi-authoritative source, at least in our modeling world, this Black and Veatch document that was used for the National Renewable Energy Lab's Renewable Energy Futures, but we do explore cost scenarios where solar costs come way down. Those look kind of interesting. We vary the gas price and we also vary exactly how much distributed generation we assume is installed in California. For the most part, for most sources of generation, we let the modeling framework decide exactly how much renewable energy to place and where on a cost basis, subject to the constraints I've described, but for distributed generation we're not able to model accurately kind of the impact of the rate structure on how customers would like to install distributed generation, so we explore a scenario in which we mandate the

Governor's target of 12 gigawatts of distributed generation by 2020. We also by default don't assume an additional California Renewable Portfolio Standard, but also examine in a sensitivity scenario what would happen if we did a 50 percent Renewable Portfolio Standard in California by 2050, leaving all other states the same.

So moving on to the first result slide, so I've shown in this picture the electricity dispatch in two different days of each month of all 12 months, over the course of WECC, so this is going to look a bit different if you zoomed down on California, but I think the basic behavior is kind of similar across the areas. So the first thing to note is the large chunk in the middle of light grey, and that's gas intermediate, which is gas combined cycle. So if we assume a WECC-wide carbon gap along with deep efficiency measures, there's relatively still a lot of room across WECC for gas to play. So sometimes I like to think of the results that we get out of this model as either, you know, perhaps you're satisfied with these results and we could go forward building this type of power system, or otherwise, maybe they're the most cost-effective results, but they don't satisfy various criteria, maybe we think gas fracking has other negative effects, maybe there's fugitive emissions from gas. So if you'd like to see this gas fraction lower, this implies that you would need to do some other policy to make it such. But that being said, you know, having this amount of gas around really lets us integrate a lot of intermittent renewables and you can see the amount of solar and wind just below that light or kind of medium grey in the center, and we're getting a lot of energy from intermittent renewables, roughly at times peaking at 30 or so gigawatts. And you see the existing pumped hydro storage, which is shown in orange, right below the solar line, I know it's a little small, it's hard to see, it's dealing with basically the duck chartish ramp that we see the early evening ramp. But because there's a lot of gas capacity around, the storage is relatively dormant and we don't, on an economic basis -- with large amounts of energy efficiency, I have to include that caveat for these results -- we don't see the installation of new large scale grid storage if you optimize the whole WECC power system to be all that economical. And this can change obviously with different assumptions, but that's something to note about these results. And it's also important to note that, once you go past 2030, which we look out to 2050, once you go past 2030, the storage really starts to ramp up. So you'd need to at least be preparing for storage to come on line because, once you get larger fractions of intermittent renewables, it becomes really quite important.

So if we take those same hourly results that I showed in the last figure and plot them on a map, and kind of compress the timescale down and take an average of it, so this gives you the average electricity generated, in other words, if you took the sum of megawatt hours generated in each of our load areas, which are shown in kind of the yellow colors outlined by black lines, if you took the sum of all the energy generated and then divide it up by 8,760 , you'd get this average generation metric that I use, I find it easier to compare it to installed capacities. Anyway, so this is an energy metric even though it's in gigawatts.

So we see that natural gas has replaced a lot, if not most, of coal in WECC by 2030, and as I mentioned before, this gives a substantial amount of flexibility to integrate intermittent renewable resources.

So what happens in terms of transmission? So in rating this slide, I realized that the title "electricity transmission largely dormant" might be a little confusing when looking at this slide at first because there's a lot of arrows of transmission going around. But I invite you to look at the magnitude of the lines that are being drawn around the WECC and compare them to the size of the generation pies, and you'll see in most cases, actually, electricity is kind of staying put and there is certainly some transmission, but kind of relative to what happens today, there's a decreasing bulk energy transmission across the West in the 2030 timeframe; once again, by 2050, this whole picture changes again and transmission kind of goes nuts.

So if we zoom in on our lovely state of California, we see that wind and hydro, but mostly wind, is imported from the Pacific

Northwest, that's that big arrow coming down into Northern California. And there's some imports from the east, but not a ton. And this is a good place to note that, actually, so we model bundled renewable energy certificate trading throughout the WECC, and we don't explicitly model all kind of the resources that go into the CAISO's 2022 Long Term Procurement Plan, the model kind of rebuilds those as they're not built yet. So that's one caveat to understand that we haven't included, that these renewable resources are going to be sited in the state, but note that there's actually a lot of resources, especially kind of in the Las Vegas area and Southern Nevada, that are right across the border from California and get piped into the state by tradable renewable energy certificates. And that's the same for wind power from the Pacific Northwest, that those lines that have kind of traditionally carried hydro power down from the north now are kind of swapped over to carry wind power with RECs.

So I mentioned that SWITCH was a scenario analysis tool, so here are 10 scenarios that we look at. I don't expect to cover them all now, you can look at them in your slides later. Once again, keep in mind that they're consistent with 2050 greenhouse gas targets. As I said in the last slide, there's a lot of imports into California, I mean, relatively a lot, I don't think it's all that much larger than the present day fraction of imports, but a lot of those imports -- almost all of them -- are renewable, in only a few cases do we see any exports of power and it's primarily non-renewable power as you'd see in the low gas price on the fourth to the left in the California 50 percent RPS by 2030 case on the fourth from the right, and then second from right for the 50 percent RPS case.

So you see that the fraction of in-state renewable generation is, you know, there's certainly some as denoted by the green, the light blue, the yellow, and the red color is geothermal, wind, solar, biopower, but this is another one of these cases where I'm not saying that these results are what should happen, I'm saying that the economics that we can see out into the future, which are somewhat limited by the fact that 2030 is very uncertain, the economics that we can see dictate that it's likely that we would import a lot of renewable power from other states, surrounding states, by 2030. So if you like this result, if you think it's the most economic efficient result, and you think that's great, then we can go for it and build it, otherwise we'd need kind of additional policies, maybe a more stringent definition of what we can generate in-state by the kind of definition of REC or something, if you wanted to bring more of these resources into the state.

So now I switch over to the actual generation capacity installed in the state. And not saying anything about where the energy is going, though most of it is being consumed within the state. And we see that really the thing that gets installed in large quantity in most of -- well, in some of these cases, namely the 12 gigawatt distributed PV case by 2020, if we make transmission expensive, the expense of transmission case, and if solar costs come down a lot, namely the Sunshot Solar case, we end up installing a lot more solar in California. In none of these cases do we really install widescale grid storage by 2030, the orange bar on the top does not really increase it all that --

the current amount represents the existing pumped hydro capacity in the state.

And so if we think about ways to incentivize California renewables, the 12 gigawatt distributed PV mandate by 2020, or the 2030 California 50 percent RPS, those can both be effective at reducing the amount of generation of gas in the state, so we kind of shove gas generation off to other states because we have a WECC-wide carbon cap. But it has not really been all that effective at reducing the amount of gas capacity in the state and, so, the different implementation options for flexibility, namely transmission storage, have not really been done and Demand Response is also one thing that we look into and the Demand Response potentials that we estimate in a Demand Response scenario that I don't show here, aren't kind of large enough yet to really change this gas capacity; by 2050, they take off and become rather interesting.

So some observations about transmission, storage and carbon sequestration. So I've mentioned before new transmission and storage is generally built after 2030, but not so much beforehand, but this is of course dependent on a multitude of efficiency measures. There's a lot of new transmission needed after 2030 to help meet the carbon cap. And natural gas, as Jeff very well highlighted, as well, really needs to be phased out between 2030 and 2050. So this kind of gas dominating the integration of intermittent renewables that I showed in 2030 is absolutely not the case in 2050. If gas with carbon sequestration is available, it is certainly used by 2050 in an economic framework, given the current projected costs of carbon sequestration, but if it's not available it's still possible to meet the carbon cap targets, it's just rather difficult.

And one other thing Jeff also highlighted, the biomass CCS option, in other words, sequestering biomass underground and using it to burn for electricity, and this can be a pretty effective way of reducing carbon from the whole energy system, especially if we couple it to transportation electrification. So by 2030, we might, if we're going to go down this path, we might have already wanted to install some. So I just have two more slides and they highlight very similar things. This slide shows the breakdown of where we think different costs might be incurred in the power sector, in different time periods, so present day, 2013, and then the four investment periods, 2020 to 2050. And 2030 looks interesting, there's certainly a lot happening, but kind of 2050 is the big story.

The key drivers in the 2030 power costs are that medium grey bar in the middle, so the increased consumption in gas in kind of the medium term, but then it's followed by a decrease in consumption of gas in the long term. And you're spending some amount of money to build up new gas capacity, but you're also spending a decent amount of money on solar power. And something that's not included here is the cost to do energy efficiency measures, so that's a whole other cost that we don't yet quantify, but it's certainly assumed in these results.

So this is the last slide that I'll leave you with. A more expanded view of the scenarios that we look at in what will become my thesis very soon, so notice the first -- before you get really worried about this chart, notice the $100 per megawatt hour highlighted red box on the scale bar, I'm not suggesting that power costs go up super exponentially in this figure, but rather there's a lot of different lines, so I've tried to highlight the differences in them. So things that seem to matter in the 2030 timeframe, certainly a low gas price would reduce the cost of power. Limited hydro, if we have some of the climate impacts of hydro and they would kind of come on early and drastically, having less energy from hydro could be a relatively large lever in power cost. But by 2050, things change around again and, you know, it's really expensive to not have carbon sequestration around unless, of course -- and by 2050, you always have to have the caveat that a lot of innovation could happen if we started now or hopefully is already happening, so perhaps the no CCS case, you could think of that as moderated by the Demand Response case, which you see at almost the bottom and it's hard to see here, it parallels the purple line with the circle near the bottom. So if we do various things, we can maybe come out with kind of an acceptable power cost in 2050, but we have to start implementing them now, so I really appreciate all the talk today about things like Demand Response, I think that's a great way to --

and great intermittent renewables in the long term, and it can make something like that top line of $200 per megawatt hour a little less scary. So I'd like to thank you for your time and take questions from the Commissioners.

COMMISSIONER MCALLISTER: Thanks very much. That's really interesting, a lot of information in those slides, which obviously we can't talk all the way through, and I appreciate all the effort that you put in over the last few years on this, and with Professor Kammen and the whole crew.

So just a couple of observations and I think I'll get to a question. Certainly the difference between 2030 and 2050 is just right in our faces as far as a time horizon problem, and you know, we know that the investments in infrastructure that can be relatively long lived, are forward commitments in a very real way, so I guess I'm wondering maybe you can talk a little bit about how the model deals with if we invest in gas in the near term, you know, how does it sort of deal with the transition over to non-gas technologies to sort of get us all the way to the finish line in 2050.

MR. NELSON: Uh-huh. Yeah, so it doesn't explicitly model kind of any market structure in which these gas plants could get cost recovery. When the model ends up installing a gas plant in a certain time period, it does so looking forward and seeing does installing that gas plant make sense in 2030, but also 2040 and 2050? So when there's all that gas available in 2030, it is implicitly assuming that you're turning them down. I think, you know, this obviously creates really interesting things that could happen from kind of a more market perspective, but in terms of what actually happens in the modeling perspective, the capacity factor of those assets gets turned way down, but they still kept on line for a handful of hours, and in those handful of hours, they're extremely valuable, so that's part of the reason why you see a decent amount of gas capacity in 2050, even though it's not being run much. And I think one of the important things to think about in this kind of gas stranded asset problem is also just making sure we actually set long term targets such that if folks are actually figuring out this type of thing out by the market, that the market knows where we're going, there's more certainty in terms of where we're going, so that at least there can be some look at the future in terms of those gas plants knowing, "Okay, we're only going to get paid in a few hours, but we're going to get paid a lot."

COMMISSIONER MCALLISTER: Yeah, so in a lot of ways, this is a very current discussion. You know, we're talking a lot about capacity markets and how to enable capacity of different flavors. And I guess a big red flag is sort of how does our regulatory apparatus engage with these issues, you know, it takes a long time to site a power plant, to get new resources developed, you know, whether it's here or over at the PUC, kind of develop the regulatory structure around those sorts of things. And so that's a many multiple year kind of activity typically. So I just find myself thinking about, okay, how can we engage in a coherent way, in a relatively nimble way, to enable decision-making in the time horizon that it's needed and allow ourselves to get ahead with some of these new technologies, whether it's storage, Demand Response, or what have you, that whole list there. And I guess I'll just end by making an observation about, you know, Chair Weisenmiller mentioned the behavior being a non-started back in the day and, you know, we are talking about with Demand Response, and there's tons of new technology that can enable it, and it's not as sort of stark of a behavior contrast, you know, and necessarily you'll make the decision once, and then sort of put it in place and automate it at the various levels in the grid, whether it's the customer on up to the region, or community, what have you. But whatever we put out there, whatever is developed, you know, needs to be relatively flexible, nimble, and be palatable for customers, and so I think we have to keep that in mind, as well. So particularly -- if and when we're working through the utilities or other entities that actually have these customers and need to treat them right and keep them, they have to be offering services that the customers actually want. So lots into the soup here, but really great work highlighting a lot of kind of interesting tradeoffs and it seems like this will have some fairly long term relevance.

MR. NELSON: Thank you.

CHAIRMAN WEISENMILLER: Yeah, thanks. I

think my observations, I'd probably start with a John Geesman quote, which was that John thought once you're looking at 2050, it's probably more astrology than analysis, so that at least there's lots of uncertainty and lots of changes. I mean, if you look back at huge, you know, to think back 40 years or so, or 30 years ago, like when we started, and start saying there was no Google, although there was no Facebook, there was computers were those huge things somewhere that you fed cards into, so we're going to need a lot of innovation and particularly in the energy space, and it's very good to get a sense here of where some innovation needs to be, so that's really the valuable part here.

On the new nuclear, I was going to ask if you're envisioning fission or fusion?

MR. NELSON: Oh, fusion, yeah, the new nuclear scenario needs to be taken with a grain of salt, it turns out it's basically kind of an economic test that says would it be economical. And we don't even allow it to be built in the state, we allow it to be sent in by wire, and it turns out, well, yes, it would be in theory, but it's not necessarily economics that drive the nuclear story, so -- in part, certainly, but not totally. So, yeah, just take it with a large grain of salt -- but fission, certainly.

CHAIRMAN WEISENMILLER: Your friends at Livermore might not like that comment.

COMMISSIONER MCALLISTER: Thanks very much. So I'll pass it back to Suzanne and I think we have time for some public comment.

MS. KOROSEC: Yes, we do have time if there are comments or questions on any of the morning's presentations, I know Mr. White from CEERT indicated his desire to make a comment.

MR. WHITE: How's that? Okay, thank you for having this workshop and thank you for letting me speak. I think that keeping our eye on the far horizon is a really important thing to be doing now, given the opportunities and the challenges that we face. I agree with Chairman Weisenmiller about the uncertainties regarding 2050, but I think it's important that we begin now to look back from what success would look like in that period and what the challenges are, and what the opportunities are. This is as much of the exercise that we undertook in the Renewable Energy Transmission Initiative under

Commissioner Geesman's leadership, which was to look back at what transmission would be needed to meet a higher level of RPS, and so we have more planning to do now than just transmission, we have to plan for decarbonizing the grid and for an ultra-low greenhouse gas emission level in our energy system as a whole. I think it's important that we recognize the importance of decarbonizing our electric grid if we are going to become increasingly dependent on that electric grid for transportation services. So when we think about raising the renewable target or the greenhouse gas target, we have to keep the Electric Vehicle, electrification of trains, all of that in mind because it means we're going to need much more clean energy than if we're simply trying to meet an RPS target.

I also want to follow-up on a note that Tim Tutt referenced about it's not time to raise the RPS to 51 percent, or whatever. I think it's fair to say that it's not time to raise the existing RPS and its apparatus and its buckets and its complications and its effective bias against some parts of our Western Grid, and I think we need to think about geographic diversity as we look ahead to both renewable targets, as well as the need to export. I think one of the critical issues in getting to a zero energy load balancing system is to take good advantage of export and imports. There's times of the day when we're going to be able and need to be thinking about exporting east to other states because we're going to have so much generation in the middle of the day with all of our solar. We also have to think about the role of imports. Traditionally, imports have been an important part of balancing California's Grid, the hydro swaps and the seasons and also the imports from the southwest. Those areas now are getting off of coal and that transmission is going to be freed up and it's going to give us opportunities to bring renewables in from places like Utah and Wyoming, over existing lines. The municipal utilities have very valuable assets in this regard, as well as WAPA, so those resources can be matched to very very cost-effective, inexpensive resources, renewables that can be developed in other states. So our planning about our infrastructure needs to be much broader than something like an RPS, we need to really be thinking about decarbonizing the electric grid and participating in regional markets, including transmission, things like the energy imbalance market are going to be very important and a harbinger of things to come. So I think that this is an important part of our planning, is that we're not just talking about having renewable mandates be increased, okay? What we're talking about is having clean energy be the basis of meeting system needs, and what that means is that the renewables, the distributed generation, the energy efficiency, the Demand Response, all have to be organized and valued in a manner that reflects their contribution and their ability to contribute to meeting system needs. The ISO is involved at the moment in a very important process, a fairly obscure acronym, the Flexible Resource Adequacy Criteria Must Offer Obligation, and in the fine print of that proposal, we will determine the extent to which Demand Response and energy efficiency and distributed resources will be able to participate in meeting the flexibility needs of the future. And it's important that the ISO's planning with that regard have the low greenhouse gas emission needs of the future in mind.

I also think, as Chairman Weisenmiller noted, that the capacity market, or capacity auction, or the capacity payment process that's now being discussed by the PUC and the ISO is an important way of bringing Demand Response and other preferred resources to life. One of the things I would observe about Demand Response is it's a little bit like that Mose Allison song about everybody crying mercy and don't know the meaning of the word; everybody is talking about Demand Response, but how do we get it going? And our friends at the PUC have been part of the problem, as have our friends at the ISO, because both have different reasons for not enabling Demand Response, but the fact is it's not been enabled and, as a consequence, it's not available in robust numbers to meet the immediate needs that we have for the system. So all of these details that are in front of us in the near term are going to dictate our ability to meet these goals in the long term. So, to me, we have to begin with what's right before us, the chances and the choices that we face, meeting the needs of San Onofre, as well as the once-through cooling, but at the same time keeping in mind and having a planning objective and a framework that recognizes that we need to get the least emission strategy going forward.

A couple of specific suggestions, I think the CEC siting process for natural gas plants needs to become more robust. I realize everybody tells the story about the Legislature said we no longer will have the needs test, but that's not to say we can't have a robust alternatives analysis, particularly about the extent to which the gas plant has other competitors that, over the long term, might well be environmentally superior. And I think we can have that conversation in the context of the siting process without disabling the opportunity to build new infrastructure. I also think that, as we look at gas plants, we need to think about contingencies in terms of permitting and recognize that, while there is a long lead time, if we get started now to do some contingency permitting with the process that we have, we should be able to be quicker on the draw once we make a decision that we need some plants. And for my colleagues in the environmental and environmental justice community that don't want to build new gas capacity, I think it's important to recognize the difference between capacity and energy in the context of this debate and that getting plants built that then are limited in how much they have to be called upon is not a bad outcome here, and I think, you know, the extent to which we can marry the economics of building these projects with the understanding that we want them to run as little as possible, will make the air quality siting -- and, again, this at the same time that we have robust expansion of opportunities for the preferred resources.

Lastly, I think that we have to think about modernizing our gas fleet so that we can weed out the technologies that are not suitable to the purposes of the future, we've got a lot of plants that are on a 40 percent minimum load and 90 minutes to full power; in the middle of the day, we're not going to want those plants on, we're going to want them modernized and updated and made part of a fast response, quick ramp fleet that can be minimized and yet still be available to provide us with capacity.

Transmission also needs to be combined

with this long term view and we need to particularly see that the DRECP is heading us towards greater dependence on the less environmentally sensitive areas of the state, this includes especially Imperial County and Riverside East, these are areas where transmission needs to go and be expanded to enable those resources to come out, that's a part of the 2030 vision because whatever other scenario you have, there's going to be a need for those transmission links.

And then on the issue of innovation, one thought is that perhaps when we get time to look at the Scoping Plan and the allocation of funds for the AB 32 revenues, we should look at something like an innovation tariff that could be administered to provide incentives for the kinds of technologies we need, be they storage, be they advanced DG, I think it's time to think about combining those programs and maybe running them through the Air Resources Board rather than through the PUC. I think the PUC's success has occurred in other areas rather than in running procurement for multiple technologies, and I think we need to think about the distributed technologies especially that are needed to meet greenhouse gas goals, whether it's low emission methane digesters or other kinds of utilization of fuels and resources that are needed to meet the greenhouse gas goals, I think that's not a purely energy decision, it's one where there's significant environmental externalities to be managed, and I think that also will be infrastructure that we need to have in place by 2030 and beyond. So with those comments, I'll leave you to any questions you might have.

COMMISSIONER MCALLISTER: Thanks, John. I would encourage you to submit some written comments on that. I know you -- well, you may already have those prepared. But, yeah, good stuff. I mean, obviously the heavier the lift, you know, you brought up some probably what would end up being some jurisdictional issues toward the end there --

MR. WHITE: Well, you have good public process, better than almost anybody, so we tend to bring ideas to the Energy Commission in part because it's a place to get them vetted. The IEPR has served this function and I think during the process we're now in between the agencies, Chairman Weisenmiller's leadership and your role in important, so even though there are jurisdictional issues, we think the conversation is good to have here.

COMMISSIONER MCALLISTER: Oh, certainly. Thanks for that and certainly we've got to start somewhere, so getting it on the table and talking about it is the first step. So thanks.

MR. WHITE: Thank you.

MS. KOROSEC: The next person who has asked to speak is Ray Pingle from Sierra Club.

MR. PINGLE: My name is Ray Pingle from the Sierra Club. Thank you, Commissioners, for the opportunity to present my comments today. I wanted to make one brief comment on the cost of concentrating solar power with thermal storage that Mike had mentioned in his presentation. And at the March CEC workshop on the LCOE workshop, a draft report indicated that the LCOE cost of solar generation with -- I think it was 10 or 12 hours of thermal storage -- was in the range of 13 to 14 cents per kilowatt hour, which was very similar to the LCOE for natural gas-fired plant, newly built combined cycle plant, which was also very close to the cost of a 100 megawatt solar utility. So while the solar storage for CSP plants, the capital costs, the initial costs are high, the LCOE is, at least in this draft report, it was a draft report, it's not finalized yet, is similar to other generation.

I wanted to start off with two context things. One is that we've been talking about 2030 and also the context of 80 percent reduction by 2050, and yet we all read the papers, we all read the scientific reports that global warming is happening much more rapidly, impacting our society much more severely than was previously forecast, and I think the way that many of us would read the political tea leaves is that we will come up with more aggressive goals, much more aggressive than 80 percent by 2050. And so I think we need to keep that in our assumptions. We don't want to take the accounting perspective, and I've got some good friends who are accountants, it's just looking backward, looking at what is the case today, we need to make reasonable assumptions going forward. So, a) I think we need to be putting these plans together, and the context most likely scenario is that we're going to be doing things faster because we have to.

The second context is we're basing all this on economics. Sierra Club is all in favor of putting forth cost-effective scenarios, we do care about cost very much, but we have to put it in the context if we're looking at cost in this case of electricity, but what are the costs of electricity if we save a few pennies on the electricity sector, but it cost society dollars? That's a bad investment. And so I think the economics we should put in that context.

The last main point I wanted to make is what gives the Sierra Club the greatest concern is when we hear news of building new gas-fired power plants, and I'm very empathetic with Mike and LADWP, you've got a huge lift with coal plant retiring, OTC, tremendous amount of change, and you have to make it work because I know heads roll if the lights don't stay on, so I really do appreciate that; however, having said that, I think we look at when do we need these resources, how many years do we have before we really need them, and I understand we have to plan ramp times to build gas-fired or whatever else we might do, transmission, but how many years do we have?

Will these technologies work? And what are they going to cost? So, on the when do we need them, we don't need all these OTCs to be re-fired in the next five years or so, we've got some time, so maybe we've got the first one coming up that we need to consider, but the solution to that doesn't have to apply to all the other ones. As far as what technologies can we use to integrate renewables, there are a number of storage projects underway, PG&E has got its four megawatt program, we've got Anatolia with SMUD, there's international projects going on all the time. I think in the next three or four years, we're probably going to have a pretty good idea of how these things work, how well they work, the best ways to deploy them, and so I think we should make a reasonable optimistic assumption that let's assume that we'll know -- and of course, it will evolve for decades -- but we'll have a basic understanding of how these things can work in a few years, and if that doesn't happen, then we go to Plan B.

There's also the DOE-funded JCESR project which started last year, and the goal of that project, as many of you know, is to create a battery that's five times as energy dense and one-fifth the cost within five years. The German Government has launched a similar project. Whether they absolutely succeed or not, I think there's a fairly high likelihood that they will on a global basis come pretty close to that. So I think the technology is there, well, certainly within the timeframe over the next few years, to avoid the need to build a lot of natural gas-fired plants. And then, in terms of what the costs will be, if the DOE is at all successful, some of these other research efforts and commercialization efforts are successful, it will be cost-effective, especially when compared with natural gas-fired plants that are presented from Berkeley, were saying that these gas plants need to be phased out between 2030 and 2050. So then if you start looking at the LCOE cost of some of these natural gas plants, instead of having a 40-year economic life, they have a 20-year economic life; those get to be very very expensive. So anyway --

CHAIRMAN WEISENMILLER: Yeah, although I'd point out the contracts for the plants are for 10 years, I would probably argue that 20 is a more coherent approach, but they're not 50-year contracts.

MR. PINGLE: Oh, I -- well, thank you. At any rate, so the biggest concern we have is the continued discussion of the need for a lot of new natural gas-fired plants, repowering all the OTC plants with natural gas-fired plants. We would just urge the Commission to really explore taking a more nuanced approach to do the absolute minimum necessary and start building in some of these more likely assumptions that battery storage and other storage technologies will be coming on board cost-effectively, and they will work within just a few years, they already are in many cases. Thank you very much. Any questions?

COMMISSIONER MCALLISTER: No, thanks very much for being here. I appreciate it and I think there's a lot going on in the storage space and a lot of differing opinions about that last statement you just made, but I think there's such a diversity of technologies out there, that there are likely to be some good winners in there and, you know, we're kind of in the mode of supporting across the board, and see which ones emerge and help the marketplace figure that out.

MR. PINGLE: Yeah, and I think it's a portfolio of storage solutions. I spoke mostly to energy storage, but there's many others, as well.

CHAIRMAN WEISENMILLER: Yeah, that was very good. We appreciate your comments. I guess the good news is, relative to Germany, we are not building new coal plants.

MR. PINGLE: Thank you very much.

MS. KOROSEC: All right, does anyone else in the room have a comment or a question? Can you come up to the microphone, please? Thank you. And identify yourself for the people on WebEx.

MR. VESPA: I'm Matt Vespa from the Sierra Club. I just had some questions on some of the presentations that we saw, specifically -- and thank you very much for this opportunity -- for the CAISO, you talked about increased regional coordination, benefits of renewable integration, enlisted reserves, sharing dynamic scheduling, energy imbalanced markets. Can you talk a little bit about how those benefits translate into your modeling and procurement decisions, so actually see the benefits of energy imbalance market, for example, and avoiding new gas commitments?

MR. LIU: In our modeling, if we model the joint dispatch, so that's beyond the current energy imbalance market. Currently, energy imbalance market is just getting started and the ISO is working with (indiscernible). However, in our modeling, we are assuming that all the balancing authority areas are dispatched jointly, so that's beyond that. And in our modeling we have not the models, the reserves sharing yet. That's an area that we have to explore, the possibility, the assumptions, how much can be shared, and the (indiscernible) certain kind of area, and between certain balancing authorities. And for the dynamic kind of scheduling, we are modeling that some of the resources from our side of the state can provide load following in the reserve. That is a portion of dynamic because hourly fixed schedule that the resources cannot provide that, so we are modeling that as a portion of it. If we have a full scale, we don't have full scales, so not everybody and the Air Resources (indiscernible) state can provide it.

MR. VESPA: So we hear a lot of the

benefits -- this is kind of a little awkward here -- of EIM, so for example, flexible capacity procurement, reducing the flexible capacity needs within that regime, having been in that RA proceeding, you know, EIM was talked about, but the benefits were never expressed, or the potential benefits were never expressed. So when can we see that coming? Would it be the next year coming up?

CHAIRMAN WEISENMILLER: It might be after the FERC approves it.

MR. VESPA: Yeah, but we're talking about -- I understand that, but it is something that's coming and I think, when we're talking about planning for the future and what our needs will be, my sense has been there has not been a sense of what those benefits could potentially be within those contexts.

CHAIRMAN WEISENMILLER: Yeah, that's fair. But like I said, I think you'll see a lot more analysis on the benefits as they move through the FERC process.

MS. KOROSEC: All right, do we have any other questions or comments in the room? All right, we have nothing on WebEx, so we're going to open the phone lines just to give those folks an opportunity. So your phone lines are open if you have any questions? All right, hearing none, I think it's time for us to take our lunch break. We had planned to return at 1:30, so we'll see everybody back here then.

COMMISSIONER MCALLISTER: Great. Thanks, everybody and see you in the afternoon.

(Break at 12:16 p.m.)

(Reconvene at 1:33 p.m.)

MS. KOROSEC: We're starting our afternoon session and our first speaker this afternoon is going to be Christopher Yang from U.C. Davis Institute of Transportation Studies. Chris.

MR. YANG: Thank you very much. Glad to see a bunch of you here. And I am talking today about electricity and Plug-In Vehicles in California, it's obviously a pretty broad topic, a lot of interesting facts just because now we have some Electric Vehicles on the market, so hopefully it can shed some light on kind of where we are now and potentially where we might be in 20 years or so.

Initially I'll put in a plug for

Sustainable Transportation Energy Pathways Research Program at U.C. Davis. We are looking at a multitude of different fuels that we think are useful, looking long term at, say, 2050 and kind of reducing greenhouse gas emissions fairly significantly. So hydrogen, biofuels, electricity, and fossil fuels, trying to understand them from a number of different factors, both from the consumer side and business and innovation aspects, as well as infrastructure for fuels, for charging, for refueling stations, and then also looking at policies and market instruments, and so forth. And all these we're putting together kind of into scenarios that hopefully can help us, stakeholders, the State, and so forth, understand what policies, what technology changes, may lead to in terms of adoption and so forth. So it's hopefully up the alley of what you guys are talking about today. So just in terms of the current context, looking at sales of hybrids over the last decade or so, 1999 is kind of when the first Honda Insight was released in the U.S., I think they only sold less than around a dozen or so vehicles that year, so 2000 may be really the first year. But what we see is fairly slow uptake until about 2004, and then really what we see in the 2004-2005 timeframe is a couple things, 1) introduction of the Gen2 Prius, which is much better than the Gen1 Prius, and then also introduction of a lot of Hybrid SUVs, so we're talking about getting kind of that model diversity that people want, so obviously not everyone wants to drive a small four or five seater, and so you start to talk about larger vehicles, and really what you see is this green bar, the blue is all Prius sales, and then green is every other hybrid in the market, so certainly the Prius is the kind of dominant type of hybrid out there.

And then after about a decade or so, we got to about three percent of sales in the U.S., it's more like seven or eight percent in California. You might have heard that the 2012 Prius was the bestselling car in California, as well, last year.

So this is the line that you want to look at in terms of plug-in electric vehicle sales, so these include plug-in hybrids, as well as battery electric vehicles. And what you see here is their introduction, you can add 10 years, so 2010 timeframe out to 2013, and the 2013 number is an estimate for this year based on the first seven months of sales so far. And what you can see obviously is that it's a little bit higher than the sales of hybrids had been 10 years ago, and that's obviously a good thing. What we're seeing is that we have more adoption, we also see a lot more models in the marketplace than we did 10 years ago. In 2003, there were still only three hybrids out there, the Insight, the Civic, and the Prius, whereas I think there's something on the order of 10 or 15 different electric vehicles out there.

So as I said, adoption rates so far have been pretty good and I think I've actually mentioned most of this, the hybrids saw a big jump. And so the big question is can PEVs keep up their momentum, so a big challenge, again, is this model diversity question. Right now, all of the vehicles are relatively small. There is a Toyota RAV4, so that's obviously a larger vehicle, that's one option if you do want a larger vehicle, but generally speaking most of the vehicles are quite small, sort of in that small and mid-size compact size range. And so it is a challenge to imagine getting those larger vehicles just because of the cost of the batteries and the energy requirements associated with moving around these larger vehicles.

And so these tables show kind of the number of different models of different types of cars and trucks that happened over the course of the history of hybrids, as well as what we have so far in terms of Plug-In Electric Vehicles. As you can see, there's already 14 different models in 2013 for Plug-In Electric Vehicles. Again, a lot of these are ZEV compliance cars; these are cars that the automakers are bringing out essentially to meet the ZEV mandate, they're not hoping to sell anymore, and several automakers have indicated that they're not planning to sell more than the number that they're sort of required to build for ZEV compliance, partially because they're selling them at a very steep discount to their actual cost of production.

So then looking at kind of more the longer term case for PEV adoption, what we can think about is home-based charging can be a challenge in the longer term, so there's been some studies that have been done so far and about

50 percent of Californians have convenient access to charging where they park their car at night, so certainly that's one key issue. If you don't have a place to plug in your car, then you're obviously not going to necessarily buy a car. Now, there's other options for workplace charging and public charging, but, again, given the range limitations of these vehicles, something on the order of 50, 100, 150 miles is certainly reasonable. You're going to have to refuel this vehicle much more often. So if you don't have access to that home-based charging, it's going to be more inconvenient, especially given the timeframes, you know, 30 minutes to several hours to refuel your car.

And then I note here, in cities the number can be significantly lower. There's been estimates -- and I don't have a good reference for it -- but there's been estimates that, for example, San Francisco residents, about 16 percent have a dedicated off-street parking space for their car and everyone just sort of parks on the street and they try to find a good parking spot hopefully within a few blocks of their house. Certainly that doesn't provide a good infrastructure for home-based charging.

So, again, focusing down on Plug-In Vehicles in California, about 40 percent of U.S. Plug-In sales have been in California, so we're obviously over-represented in Plug-In sales; California is about 11 percent of the population, and about 23 percent of hybrid sales have been in California. And as of a couple months ago, we had about 45,000 PEVs sold in the state.

So that's kind of the near term picture of where PEVs are. I want to talk a little bit about the charging impacts. So there's a couple of different things that you need to think about, one is how many vehicles are there actually going to be in a reasonable timeframe. And I think the discussion here is about 2030, so thinking out about two decades, how many vehicles could we imagine being on the road. And then also, their timing of their charging. When are they plugging in, what are their incentives for off-peak charging, and so forth.

And then, just in terms of giving you kind of a rough rule of thumb, a million battery electric vehicles, this is sort of a Nissan Leaf type vehicle, it goes 12,000 miles a year, it consumes .35 kilowatt hours per mile at the plug, and would add about one percent to the 2030 California electricity demand. So right now in California we have something on the order of 25 million cars, so four percent of cars adds about one percent to electricity demand. And then that's for battery electric vehicle; obviously, if you have a Plug-In Hybrid that uses gasoline and electricity, that number will be lower depending on the utility factor, what percent of those miles happen on electricity. And so that's going to be a function of obviously the size of the battery, the person's driving patterns who actually owns the car, and then actually the charging availability. You know, a lot of people, once they get into a plug-in hybrid, they definitely want to maximize the amount of driving that's done on electricity, and so then you can imagine trying to plug in everywhere you can -- at work, at home, at your friend's house, and so forth, and then you can really maximize -- you can get 100 percent electric driving even with like a Volt or some smaller vehicles, depending on your driving behavior.

And then charging demand. I think this

is kind of the big question. Plug-In Vehicles can be a flexible supply following demand. Vehicles are parked 95 percent of the time, so if they're plugged in, there is potentially the ability for them to respond to signals or intelligence in the car itself to decide when they should be charging.

The other question is the ubiquity of public charging infrastructure. Again, what we find today is that a lot of people plug in just because there's a charger there, even though they don't necessarily need the charge, you know, if they have Leaf and they're only going 20 miles, and they have 75 mile range, there's an empty charger, I'll just plug in, and they'll charge their car just a little bit even though it's not necessary to charge during that time, and that might be adding to -- at least certainly daytime charging, if not peak hour charging. Again, the question is how much of this charging will be sort of "dumb" charging versus smart charging, whether it's responding to utility signals or just other timing, you know, I set a timer on my vehicle and I'm not going to charge until 1:00 a.m., that sort of thing. And then again, what are the utility incentives, and then how much do people actually respond to those incentives, just because it may be not as transparent and, as well, the cost is potentially much lower than the cost of driving a gasoline vehicle, so it might cost a dollar to charge my vehicle during the middle of the day instead of 20 cents at home, or 50 cents at home, you know, is that enough of an incentive to make me change my behavior?

So looking at some of the future projections for plug-in electric vehicles, I just compiled a few studies that have looked at this and some of them are for the U.S. and I tried to scale it down to the California context using, again, some of those numbers for the percent of vehicles sold in the U.S. versus California, both for Plug-Ins, as well as for Hybrids. And so, for example, the highest case, this light blue line here, is the National Academies did a study on Plug-In Hybrid Vehicles a couple years ago and they came up with a maximum potential case, and this is really -- they spoke with a lot of automakers and said, "How fast can you possibly ramp up production of these new technologies?" This has nothing to do with what the demand for those technologies is, but just if you were to build all of these factories now, as quickly as possible, what is that rate that you could imagine bringing these vehicles to market. And so this is kind of the curve that they developed for that case.

What you can see is -- and this is a log scale, so hopefully it's not too hard to read -- but what you can see is, by 2030, we're talking about -- again, this is also in thousands of vehicles -- so we're talking about seven to eight million Electric Vehicles just in California. Another study, I think you might have heard from others who looked at the California Energy Futures work, estimates something more on the order of three million cars in California by 2030, in this red box. The NRC had what they called a probable case, which is more likely based on both demand, as well as the cost productions that they foresaw coming, and so that's very similar to the California Energy Future project and the 2.5 million vehicle range. The ZEV Mandate doesn't go out to 2030, it only goes out to 2025, but what you can see is what we have is just cumulative sales out to 2025 is about 1.3 million vehicles, assuming that they're all battery electric vehicles, so obviously the ZEV Mandate can be met by a number of different technologies, fuel cells and so forth. So this is just a ZEV case that's assuming only battery electric vehicles, which probably is not very likely to happen.

And then in the AEO, the Department of Energy's Annual Energy Outlook, has a very low number, something on the order of 600,000 vehicles. And again, we're talking about in the first three years we already sold about 45,000 in California. So obviously this is a pretty wide range. We have more than a factor of 10 between the very high and the low range. I'll also note that the CEC's own California Energy Demand Forecast estimated somewhere between two to seven terawatt hours in 2022 and I sort of extrapolated those growth rates out to 2030, and you're on the order of five to 13 terawatt hours. And just to put these vehicle numbers in context, again, looking at that NRC maximum case, in the order of eight million vehicles, that could potentially be up to 35 terawatt hours, or 10 percent of California electricity demand, again, if those were all battery electric vehicles, and then if you assume a kind of more moderate mix of plug-in hybrids, as well as battery electrics, it's down to 24 terawatt hours, or about seven percent. And so, again, the CEC's projections, as well as kind of the more moderate cases sort of in this two to three million vehicle range, again, we're talking about kind of two to four percent potentially of California electricity demand that would be needed to supply electric vehicles.

So these numbers don't seem very big and so certainly the case can be made that we don't necessarily have to worry too much about these vehicles adding a lot of electricity demand. Again, the question is when are they charging, and if they're all charging at 5:00 p.m. or 6:00 p.m. on a summer afternoon, then obviously that can be quite problematic, but most people would think that the majority of vehicles, again, would be charging kind of in the evenings and you really just have to provide small incentives to get people to either not plug in right away when they get home, or plug in, but have essentially a timer if you want to go fairly crudely to change the charging to a midnight or 1:00 a.m., or actually that you can have some even greater intelligence in that charging process.

Looking specifically at the issue of timing of vehicle charging and perhaps more importantly at the flexibility of that vehicle charging, this is a study that I did that really looks at the potential for vehicles as a flexible load, and their ability to help essentially follow demand, so thinking out to 2030 timeframe, you can imagine, well, in the near term we have kind of what I like to call active and passive elements to the grid. So active things are essentially load following, things that respond to conditions on the grid, so a natural gas power plant is something that can ramp up and down in response to changes in electricity demand, and what we tend to think of demand as being as passive, you know, people turn on their lights or turn on their air-conditioners when they need those things, and there's fairly -- I mean, there's obviously Demand Response programs, but the ability to change the timing of that is right now fairly small. And so this is kind of the current paradigm. But we also obviously have a lot of what I would call passive generation that's being added to the grid, these are wind, power plants, solar PV, as well as utility scale solar thermal. And they are also not as able to respond to grid conditions. They generate when the resource is available and the grid essentially has to respond typically with kind of ramping up and down of these natural gas plants. But we can also imagine vehicles or other grid storage on the system that can also essentially dynamically respond to those changes that we see in terms of that passive generation. And so this is just a -- I'll show a couple of slides that show kind of the simulation of using a grid dispatch model for California. I'm looking at about 25 percent PEV penetration in 2030, which amounts to about six percent of total electricity demand, and a very smart charging system, so one where the charging is directly responsive essentially to when the best time would be to charge -- in this case, from a utility's perspective. So what you can see here is, down at the bottom, just kind of the different resources that are used to meet demand, so nuclear, we have a lot of renewables, in this case it's a wind intensive case, so it more follows wind generation, and then we also have some hydro, and then the rest is natural gas, either combined cycle, or combustion turbines. And what you can see is that the model essentially decides when these vehicles are charging, they mostly occur, you can see, at nighttime, so in the troughs here you have high kind of charging, and this red line indicates when the vehicles are charging, and you can see they follow somewhat the wind profile. So the wind is sort of kicking up after the peak electricity demand, and so that's kind of when the electric vehicles are also charging, and at nighttime, as well, also just to level the load and increase the capacity factor of some of these more baseload plants, or the combined cycle plants. And so you can also just see what kind of the marginal and average emissions associated with that are.

In this case, looking at not a wind intensive grid, but a solar intensive grid, you can see that -- so this is the solar generation by day, and then you can see the demand sort of peaks later than the solar generation does, obviously, solar generation typically peaks around noon, peak electricity demands are in the early to late afternoons. And so what you can see is that there's excess solar generation in the early mornings when solar generation is ramping up, but that the electricity demand hasn't quite followed, quite caught up yet, and so there's a lot of these excess generation where the vehicle charging is all occurring in the morning, the middle of the morning, you can imagine that would correspond to these people driving to work and then plugging in right then. But again, this is sort of an optimization approach, so it doesn't necessarily take into account exactly when people would want to charge, this is a system analysis that looks at when would be best from a utility perspective.

So then just to kind of summarize what you can see, on the left side is the wind intensive case, and on the right side is the solar intensive case. You can see the most charging occurs in the wind case early in the morning, 1:00 to 4:00 a.m., and then each of these columns is a month of the year, and this is 24 hours of the average day of that month. And then what you can see here for the solar intensive case is that we have essentially a charging occurring mostly right after solar generation starts, but before that peak starts to ramp up in electricity demand.

And then the bottom graph just shows the marginal vehicle emissions associated with charging those vehicles.

Again, just thinking about these Electric Vehicles and the grid in the longer term, right now what I was describing was flexible charging, so it's kind of a one-way process, vehicles choose to charge or not, depending on signals from the utility or prices that they might receive. You can also imagine V2G flow of electricity into cars and potentially out of cars. There's been some demonstrations early on looking at just regulation services and so forth, but just with the potential even for kind of firming renewable resources and so forth. Another potential issue, or benefit of plug-in vehicles is that, even after the batteries are essentially retired from vehicles, they may still have quite a bit of useful life left, 70-80 percent of their capacity. And so there's been some studies looking at the second use of batteries as grid storage and I note here that 100,000 used PEV batteries can provide about 1-2 gigawatt hours of grid storage after it's retired from the car.

So in terms of generation, again, the numbers on the order of a few percent are probably not very concerning from a generation asset standpoint, but the distribution level effects can be quite important. So what we've noted is there's quite a regionalization of sales. I noted that 40 percent of the PEV sales in the U.S. are in California, you can actually disaggregate even more and look at, you know, it's happening mostly in the coastal areas, both the Bay Area, as well as Southern California, it's heavily skewed towards those areas. So once you get down to even the neighborhood or Zip Code level, you can see there's a very strong clustering of these vehicles in certain neighborhoods. And as I note here, Nissan Leaf uses about 4,000 kilowatt hours per year, which is similar to an average California home, a little bit less, but on the same order. So, again, if someone goes out and buys a Leaf or a Tesla, or something like that, that can add obviously a significant amount to the substation, as well as the individual pull transformer level and that's something that the utilities need to concern themselves with.

This is just a picture from San Diego, and what you can see is that we have really strong clustering of sales. Each of the green dots is a PEV sale in California, and there's fairly strong clustering in certain neighborhoods in certain areas, and it's mostly going to continue to follow the same pattern over time.

So I'll just briefly mention one other thing that is relevant. So within our next steps program at ITS, we're doing some energy systems modeling for California, again, trying to understand the technology options for meeting these deep greenhouse gas reductions by 2050, and so obviously our primary focus is looking at transportation, the vehicles, the fuels, as well as the electric sector and trying to understand how all these pieces can fit together to again meet our greenhouse gas targets for the 2050 timeframe. And so just some, I think, relevant results from this modeling, it's still ongoing, but what we see is that by 2050 electricity has to be almost fully decarbonized, potentially nuclear, certainly significant renewables, and then some fossils with CCS is found in many of the scenarios that we developed. Transportation reduces the emissions, but certainly less than other sectors, and then we have significant increases in vehicle efficiency and use of biofuels. And then at least one of the prominent sort of technology options that the model seems to like is biofuels made with CCS, so that's essentially a negative carbon option because we can take the carbon that's in the biomass, make some biofuel, and sequester a significant amount of carbon and we actually get essentially an offset, which lets us continue the use of petroleum.

Okay, so just to kind of sum up, there's still a lot of questions remaining about plug-in electric vehicles, they're in their infancy and commercialization. There was obviously a lot of pent up demand among early adopters who wanted electric vehicles, and so they were waiting quite a long period of time, and they may have purchased hybrid vehicles to sort of satisfy their demand in the near term, but there was certainly a number of people who were waiting for that. And so then the question is, who are those next buyers going to be of the Generation 2 and Generation 3 vehicles? How many of them are there? And can we actually reach sort of this early mass market, kind of the place that we are with hybrids where we're starting to talk about not just a percent or two, but five or 10 percent of the market, still not maybe as big as we would want it to be, but it's a place where we need to understand what the needs of the market are in terms of range and body styles and all the things that go along with it. And then there's other questions about, as I said, larger vehicles, how important public infrastructure is given the issues associated with home-based charging, and not only in terms of consumer adoption, but also again in terms of the impact on when people charge and the timing of that charging, and then how much will smart and flexible charging actually be used because that can certainly make a big difference in the ability -- or in the desire of utilities to kind of push these vehicles out, as well.

So just in conclusion, PEVs are doing

right now quite well by many measures in the very early market, but again there's uncertainty about the pace of growth and the range of estimates for 2030 is understandably quite large, there's a lot of uncertainty about what they're going to be like, how many there are going to be, and what the consumer adoption will be.

Again, the demand for electricity from PEVs is going to be fairly modest in the 2030 timeframe, you know, the range is on the order of one to 10 percent of California electricity, but maybe two to three or four percent seems more likely. And then, again, this issue of flexible charging V2G, V1G, is important for helping make the case certainly from the utility's perspective, to make EVs kind of good citizens on the grid and it helps balance renewables. And certainly the question of how those utility incentives are structured to induce consumers to act like good citizens is important. So that's all I wanted to say. And I'm not sure if there's questions?

COMMISSIONER MCALLISTER: Thanks very much, very nice. I guess it would be interesting hearing a little bit about kind of the public policy issues that some of this brings us. I mean, you mentioned, okay, the utilities have to figure out where these things are going to go and what that means for their grid. I totally agree with that. I guess really in terms of a question, I mean, we need analytical rigor and some reasonable scenarios about what is likely to happen to be able to stage those investments in a way that's kind of optimized. I'm wondering if you're sort of broadly aware of the work the utilities are doing on that and sort of if there's a broader group that's trying to get a head around this to look at the rate impacts and other issues like that?

MR. YANG: Yeah. So I'm aware that the CPUC is involved with trying to understand both from a policy perspective looking at rate impacts, and one of the questions that I'm aware of is looking specifically at like the Low Carbon Fuel Standard and trying to understand how those incentives, which can accrue to utilities, can be used within the utility, you know, for all the entire rate base, or just for electric vehicle infrastructure and so forth, so certainly that's one question of looking at this. But I think --

I'm not totally aware of all the things that the utilities are doing in terms of developing these scenarios. I know that there's been a number of, again, these kind of projections out there and academic groups, as well, both at Berkeley and U.C. Davis and Stanford have been looking at quite a number of these issues, both in terms of the grid impacts, as well as of just trying to understand kind of the sales and charging impacts associated with that. But, I mean, it's a fairly complex question because it brings in the uncertainties associated with the consumers and their choices about vehicles, as well as uncertainty about when they might charge those vehicles and the regulatory structure that the utilities kind of find themselves in is really going to be dependent in some sense on those first two questions.

COMMISSIONER MCALLISTER: Yeah, I think that's a good observation. I mean, that's sort of the flip side of the DG discussion with net metering and everything where you have customer adoption that tends to be clustered, if it, in this case, you know, pops a bunch of transformers, or inspires the utilities to have to invest, costs that the utilities have to invest in distribution infrastructure, quantifying and sort of analyzing it, figuring out what the timeframes are, what the scale is, and then it really does need to be a policy call, which presumably over largely at the PUC for the case of the investor-owned utilities to figure out, okay, how to allocate those costs, whether they get passed on to ratepayers or not, if not, and how that happens, or if so, how that happens, etc. So interesting bunch of questions your presentation begs.

MR. YANG: Yeah, and I don't have a lot of good answers, unfortunately.

COMMISSIONER MCALLISTER: Nor am I expecting you to, necessarily. But I guess, you know, the flip side of this is that the utilities certainly are also seeing this as an opportunity to kind of invigorate that aspect of their businesses, and so it could have an upside, as well, but obviously needs to be managed. I wonder if Chair Weisenmiller has any questions.

CHAIRMAN WEISENMILLER: Yeah. I was just trying to understand, when I looked at your solar and wind results, I wasn't quite sure if these were just the sketchy simplifications of dispatch of whether --

MR. YANG: Yeah.

CHAIRMAN WEISENMILLER: -- yeah, I was going to say, obviously you have to really get all the operational constraints in, and as you put more of the operational constraints in like minimum load for gas plants, or a split of hydro between pondage run of the river Storage, what you tend to do is drive down marginal cost and drive up average costs, the costs associated. And obviously trying to get it just right is very hard.

MR. YANG: Yep. Good, thank you.

COMMISSIONER MCALLISTER: Great. Thanks very much.

MR. YANG: Thank you.

MS. KOROSEC: All right. Our next speaker is going to be Lorenzo Kristov from the California ISO.

MR. KRISTOV: Good afternoon, Commissioner Weisenmiller, Commissioner McAllister, and guests and participants. What I have teed up for discussion today is a topic that I believe is important, that I have not heard discussed very much in policy arenas, and like some of the other presenters today, will probably raise more questions than offer answers, but hopefully some provocative questions that we could all benefit from engaging in discussion of. And it really comes down from, I think, the pretty universal recognition that over the coming decade and more, we'll be seeing a veritable explosion of activity happening on the distribution side of the network, driven by a variety of things.

So what I was going to talk about today was just a quick overview of the forces of change, which I think will be familiar to most of you, and then lay out two different concepts which I might call bookends of what the future transmission distribution interface could look like. I think there are a couple of really distinct possibilities that, by highlighting them, might help us think about ways that could be better than others, or not, but I think at this point it's a question. And then I'll close with some other important elements of what a 2030 power system vision should, I think, contain, and with some basic policy considerations.

The forces of change certainly are policies to reduce environmental impacts, no question about that. We've been talking about those today, diverse rapidly emerging technologies from solar, electric vehicles, storage, etc., microgrid systems, community resources which have been talked about in the Legislature, as well as in other venues. Consumer desires for greater choice and control -- and here, I wanted to just mention desire for local resilience to disturbances, what we might call the Hurricane Sandy effect. I think that's something that, it's perhaps not played out very much in California yet, but to a certain extent erratic climate events are not things that are controllable by policymakers and yet can happen and can be game changing, especially in terms of how people think about reliability and resilience.

We've also seen that, with the penetration of rooftop solar how that changes the economics of traditional rate structures and begs the question of, well, how might those rate structures be redesigned and how might utilities rethink some of their business models in this changing environment.

If you put all these pieces together, then when we look towards 2030, we could see tremendously increasing local production of the end use kilowatt hours, that is, the high voltage transmission grid may be only transmitting 50 percent, 60 percent, or so, and a much higher percentage of it never touches the grid, is produced and consumed locally, and a proliferation of microgrids right now, pilot programs, are demonstrating substantial capabilities, but that may become a lot more desirable, especially as storage becomes more prevalent and affordable.

So why do we want to think about the future of transmission distribution interface? Why am I teeing that up? First of all, I think these things are affecting how we think about the electric system as a whole system. Transmission and distribution have traditionally been separate, they meet at a certain point that on the ISO grid we call it the PNode, and above that the ISO controlled grid is an enmeshed network that is operated as a single machine; whereas, below those PNodes, the systems are largely radial and have for decades been thought of in one particular way, which is energy flowing in one direction. But the things that we're seeing now and certainly ISO is wrestling with a lot of them, a lot of distributed generation will be counting for resource adequacy, what does that mean about participating in the ISO markets? A major element of our Demand Response and energy efficiency roadmap has been to find ways to expand DR capability to participate in ISO markets. So the forces that I mentioned on a previous page, many of them are eroding the traditional transmission distribution boundary, but I don't think we've looked at it in a systematic way as to what that erosion might mean and what might be the best way to manage it in a system that we're visualizing 10, 15, 20 years in the future. So I think taking this perspective and asking these questions now may help us consider near term policy issues from this whole system perspective, rather than piecemeal as individual needs arise.

The proliferation of distributed energy resources I think is what prompts this focus on the T-D interface and the possible entry, then, of new types of participants with new roles and responsibilities; for example, the ability to aggregate customer data and it had come up in one of the ISO stakeholder proceedings the idea of a data concentrator, an entity that would not necessarily be dispatching resources, but would be providing a service of collecting data over thousands of households, perhaps that could participate in a program, as well as the possibility of anticipating needed innovations and starting now to develop them. And I was particularly taken by a Resnick Institute report that came out in late 2012 where they talked about how control technologies, control systems, and different ways of thinking about how to control all the variability in these new innovations on the distribution grid may be managed. They asked a lot of good questions, but also pointed to research needs that need to start now.

So in laying out these two bookends, what I want to caveat with this is that I've tried to paint really extreme models in order to highlight the distinctions; neither one is necessarily preferred at this time, certainly the ISO doesn't have a position, we're just talking about it and trying to assess the possibilities. But because both of them are potentially plausible futures, let's look at them both in some depth and see what their pros and cons are and how they might work in practice. Also, they're not mutually exclusive. You'll see as I talk through them a little bit that instances of both of them could coexist for many many years, you don't have to necessarily have to pick one or the other. And also, I'm not talking about transitional processes either at this point, I'm really trying to just paint these as potential end states that we realize at some point in the future and not going to the pathway to get there.

So bookend A, the transmission plus distribution system comprised of fully integrated system with one system operator that performs scheduling, real-time balancing, integrated markets, etc., and the traditional transmission distribution boundary is eroded for purposes of markets and operations. I think a lot of the things that we're seeing seem to be heading in that direction, with lots of distributed resources providing RA, potentially having must offer obligations, bidding into the ISO markets, etc.

Bookend B, though, really takes a very different approach and says, well, what happens if we for operational and maybe even market purposes, and for business model purposes, continue to think about them as separate systems, the high voltage transmission grid being a mesh network and, say, the ISO's operational control ends at what we know as the PNode today with the transmission operator for the grid and the wholesale markets, but then some other entity is taking responsibility for the real-time operation and balancing of the distribution lines that come off of that transmission grid.

So Bookend A, the ISO schedules and dispatches this integrated system to maintain real-time balance and reliability that has visibility and dispatches distributed resources above a fairly low size threshold, maybe down to 50 or 100 kV. Bookend B, the ISO really operates with a transmission grid only, up to the PNode. And there's some entity, the Distribution System Operator, that operates a distribution system below the PNode. In a certain sense -- and I don't want to stretch this analogy too far -- but in a sense the PNode is similar to an intertie now where we schedule imports and exports, and we're looking at how can that dynamically change, what is the net energy flow, and what is the volatility of that interface from one interval to the next.

And the Distribution System Operator may be something similar to a microgrid; imagine a microgrid which might now be an industrial park, or something below a distribution node, but then may expand to actually entail the entire set of facilities coming off of a PNode. The ISO under Bookend A provides real-time services, balancing load following frequency, etc., for distributed resources, as well as for grid connected resources. Whereas, under Bookend B, the ISO is providing real-time services to Grid connected, but this Distribution System Operator entity is providing comparable real-time services for distributed resource and, from the ISO perspective, the Distribution System Operator looks like a resource. And so that interface point becomes a point of settlement between the ISO and the Distribution System Operator based both on net energy flow in either direction, as well as the volatility of that net energy flow from one interval to the next, the volatility in a sense capturing how much the ISO is providing balancing services versus the Distribution System Operator.

So at this point, I have not sketched out more technical detail, there is I think a lot more that could be developed, I just wanted to get an initial idea out there.

Other elements of the 2030 power system that I want to mention, and this was raised earlier today, and I think it makes a lot of sense, is greater coordination and integration across the Western Interconnection, and I'm deliberately saying real-time imbalance markets plural, there may be more than one, there may be three or four, one in the Northwest and one somewhere else, and one that the ISO is in the process of developing currently. But I want to also raise the consideration of possible day ahead coordinated scheduling and congestion management. This idea came up about 10 years ago in the days when an organization called SIGWE (ph) existed and at that time there was a congestion management committee, I was participating in that, and with some representatives from other areas of the West we developed a conceptual proposal for how we might virtually eliminate unscheduled real-time flows by sharing schedule information on a day ahead basis, offering to dispatch some of our resources in order to eliminate congestion on a day ahead basis, and thereby schedule actual flows on a flow-based model. That may be an idea whose time has come, or is coming soon, because when we think about the western region as a whole, there are potential inefficiencies and I'm hoping someone may have been doing this study already, of what efficiency could be gained if we were scheduling the West-wide system on a flow-based method to be able to access, say, some of the renewable rich areas in the west without having to make massive infrastructure investment, but simply by using the existing infrastructure more efficiently.

Some policy considerations. Policymakers can influence but not fully control the ultimate trajectory of industry evolution. I think we all live with that realization, but when I think about these two models, A versus B, Bookend A versus Bookend B, are there ways that we can allow both of them to evolve, or perhaps determine that one of them is much better than the other, and try and move towards it? But given that that will take some time, consider that both may end up being a part of our future and then how do we make near term policy decisions that essentially don't foreclose getting to an optimal longer term solution. And that's all I have to say at the moment. Questions?

COMMISSIONER MCALLISTER: Okay, thanks very much. Very thought provoking. I do have a question on your conceptual bookends on Page 5. You know, I guess qualitatively what are the main characteristics of a distribution system operator, how would we, you know, if we're drawing up boundaries on geography or on some other criteria, you know, is it number of customers? Is it types of diversity of load? Is it -- yeah -- the resource mix? What are the sort of axes that you would want to apply, or the sort of -- what framework would you use to sort of draw the lines around a given DSO? If you do have distribution system operators, you know, if you're going to Bookend B, what would the characteristics of that DSO be, optimally?

MR. KRISTOV: Well, I think, you know, if you start with the microgrid experiments that we have now, I think they're looking to be -- or the phrase that KEMA has been using, I think the Self Optimizing Customer, in a sense that is a Distribution System Operator, or a municipal utility today, they're doing those kinds of things. So I'm thinking here more functionally rather than necessarily institutionally. Now, you might say, well, we have utility distribution companies that have large service territories, certainly they could do this. But even within those existing institutions, there may be sublevels of optimization being done by self-optimizing customers and microgrids.

In the Resnick report, they talk about a three-tier system of control and I just kind of mentioned this towards the end without developing it a whole lot, but the idea that there's the transmission system operator level at the top, and then there's the individual microgrid or self-optimizing customers at the bottom, which could even be a house with solar panels and a refrigerator-size storage unit. But then there's an intermediate level where they mention, well, at the distribution system as a whole could be an intermediate control level, and they don't really develop that idea. So I think it could be defined as geographically small, as a single PNode.

COMMISSIONER MCALLISTER: Go for it.

CHAIRMAN WEISENMILLER: No, I just had a follow-up on his, but more questions. Obviously one of the issues in California is where the transmission system -- where things are transferred to the ISO varies across the utilities and, so, what could easily be transmission in one utility could easily be distribution in another one.

MR. KRISTOV: In terms of the voltage level, yeah, that's true. And I think the criteria that came into play at that time had to do with whether the systems were networked or not, with the idea that the ISO is managing where there's network flows, loop flows, and below the ISO take-out point is essentially a radial system.

COMMISSIONER MCALLISTER: So, yeah, you're getting at my question; I probably didn't ask it as articulately as I might have, but certainly -- really the difference, sort of the Resnick sort of three-tier characterization, you're between A and B, is whether you have that intermediary or not, essentially.

MR. KRISTOV: Yeah.

COMMISSIONER MCALLISTER: So I think it's interesting and I certainly wanted -- I was trying to get at the technical merits of what's the optimal boundary, just if we don't come to the table with any preconceptions, what would be the optimal boundary, you know, of the DSO if it does exist, I guess?

MR. KRISTOV: Yeah, and I think it could be that each individual PNode operates as an entity, a DSO in its own right potentially. But then, you know, in terms of an institution, it could operate hundreds of them within a geographic area.

COMMISSIONER MCALLISTER: Interesting. Thanks very much.

MR. KRISTOV: Okay.

CHAIRMAN WEISENMILLER: Yeah, so the

first one I have for you is that obviously the transmission and distribution systems are interconnected, and the ISO is doing a lot of analysis of sort of renewable integration issues on the transmission system. I don't know if you were here earlier today when Tim Tutt was talking about some of the renewable integration issues on the distribution system; so I'm just trying to understand what the feedback, or potential feedback is between instabilities on distribution and the transmission systems, if any.

MR. KRISTOV: Well, I think first of all, you know, to try to go further with this model is going to require really collaborative discussions on how it's going to look, you know, and what sort of technical standards and technical issues need to be resolved, many of which Resnick points to. But you're asking specifically about stability?

CHAIRMAN WEISENMILLER: Yeah, obviously, again, we have two systems and we're having similar but -- we're having intermittent resources having differing impacts on either one and how, if at all, the two interact.

MR. KRISTOV: Well, I think they do.

They will because there will be flows across that boundary in one direction or another. And I don't know that the physics matters, whether you're using Bookend A or Bookend B of the model, it's really these models are dividing up the roles and responsibilities for who is managing most of that variability and volatility. But the physics could still say, well, gee, this node which was a load node for most of the time on the ISO grid, every once in a while it turns into a supply node because it's having a net flow onto the grid. I think those kinds of things are going to happen, but this sort of argues for saying, well, you know, when we have imports and exports, we schedule net flows in one direction or another, maybe we want to move to that kind of scheduling of the PNodes on the grid, looking at them as potentially bidirectional, and sometimes the distribution system below that node is going to be scheduling export energy to put into the ISO grid, and at times it's going to be short of supply and it's going to be scheduling to receive.

CHAIRMAN WEISENMILLER: Okay, sort of switching gears to a couple of other topics, the first one is, obviously one of the defining challenges of the time is climate change, and that means a lot of us are thinking about adaptation and readiness in terms of responding to climate change, and obviously microgrid is at least the one with the tools, but it seems like, as we think through these approaches, again, we have to be thinking through what's going to enhance the readiness of our systems to deal with climate change.

MR. KRISTOV: Are you thinking specifically of volatility, you mean like extreme events?

CHAIRMAN WEISENMILLER: Yeah, extreme events. I mean, obviously I think all of us remember substations blowing up in New York when it hit water, saltwater, so the question is how do we look at our systems and look at the extreme events, what's likely to occur, and how do we have a more resilient grid to deal with those events?

MR. KRISTOV: Well, I guess what strikes me is that there will be a lot more growing interest in the ability to retain local service if you can disconnect from the grid, islanding capability. Right now the standards say that if you lose your connection to the distribution grid, then your solar panel inverter switch is off and you lose power. But it's not farfetched to say, well, that can be changed if you have safe ways to enable islanding under situations where a major event occurs and then perhaps cities or areas within cities, or campuses, or colleges, or hospitals, can retain their own power supply without having to use a backup generation, perhaps with renewables and storage, and sophisticated electronic control systems.

CHAIRMAN WEISENMILLER: And certainly in New York some of the CHP systems held their load no matter what, you know, on some of the campuses.

MR. KRISTOV: Yeah.

CHAIRMAN WEISENMILLER: Yeah. Another question, again, sort of broadly thinking about what our issues are, is obviously we've had at least one incident at one of our substations, so in terms of trying to do cyber security and other issues, you know, again, how do we have looking at T&D in the future, how do we make sure again we have a resilient system that can deal with those types of incidents, the cyber security or terrorism?

MR. KRISTOV: Yeah. I think that's a crucially important question, but it still seems to me that, you know, more local autonomy, local control, local resilience, may be an important part of the answer.

CHAIRMAN WEISENMILLER: Okay, thank you.

MR. KRISTOV: You're welcome.

MS. KOROSEC: All right, our next speaker is going to be Lee Friedman from the Goldman School of Public Policy at U.C. Berkeley.

PROFESSOR FRIEDMAN: My thanks to the Energy Commission for inviting me here today and to all of you who are listening. The talk that I'm going to give is based on work that I've been doing over the last year that started with the California Council on Science and Technology. That was asking the question what are we going to do, what policies are needed after 2020 in order to keep California on track to its long run greenhouse gas reduction goal. And my piece of that problem had to do -- this is a big committee with a lot of people on it, I think you've heard earlier from Jeff Greenblatt -- my piece of that as an economist had to do with pricing policies as they relate to the electricity sector, so it's the nexus between greenhouse gas reductions, pricing, and the electricity sector. And I'd like to begin with the bottom line of what comes out of my study, just in case we run out of time, so it's always good to have these things upfront.

The first recommendation that comes from the study is that the California Legislature should act soon to create more certainty about the magnitude of greenhouse gas reductions that will be required in the 2020-2030 period.

The second recommendation is that more emphasis during this period from now to 2030 should be given to expanding partnerships and linkages with other jurisdictions that are adopting comparable greenhouse gas reduction goals and policies.

The third is that legislative restrictions that currently prevent most electricity consumers, residential consumers, from receiving any carbon price signal in their electricity rates should be revisited, especially as these consumers would receive dividend compensation for those rate increases.

And finally, California should begin soon to transition gradually all of its electricity customers onto time varying marginal cost-based rate structures. So there are definitely policy implications that come from this study.

On this slide, I just try to give an overview of what the whole study does. It begins by looking at the fact that we're going to need a lot of greenhouse gas reductions in order to meet that longrun goal, and that's inevitably going to mean that our electricity will have to get cleaner and probably that a lot of that electricity will be used as a substitute for dirtier fuels right now. The simplest example of that, you've been hearing about already, would be vehicle electrification, that instead of running cars on petroleum, we clean electricity even more than it is now and run more cars on it, but there's plenty of other examples of that type.

And so as we go about this business, how do we choose which greenhouse gas reductions to make as we move forward over time? And the main operating principle is to choose the least cost ways of reducing the greenhouse gas emissions in order that we maintain citizen support for going down this path and to entice other jurisdictions to undertake comparable efforts. As we do that, there will be a lot of decisions made by government regulators, building standards, appliance standards, but there's going to be a ton of decisions that are made about ordinary people going about their ordinary lives, setting their thermostats, and making many decisions and deciding whether to buy an electric vehicle or not, and all these people are going to be influenced by the prices that are being charged for their energy using decisions.

And there are four critical reasons why these prices are likely to diverge sharply from the social marginal costs, unless we do something about it and so that's where the recommendations that I mentioned earlier come from in this study.

So I mentioned in the beginning that the problem is we have to reduce greenhouse gas emissions by quite a bit, and that's going to require a cleaner electricity supply and greater use of it as a substitute; but how quickly do we do this? Where do we start? Which things do we decarbonize? And which fossil fueled activities do we switch? And when do we switch them? And who decides the answers to these questions?

And the operational principle is to meet the environmental goal by choosing the least costly set of greenhouse gas reducing actions. As I mentioned, that's important for maintaining popular support and it's important for encouraging other jurisdictions to act comparably. But there are a bunch of complications in this. One is there's great cost uncertainty. We don't know how much a lot of things cost in terms of achieving greenhouse gas reductions. We don't know, as an example, just how much inexpensive energy efficiency improvements there are out there. We may know a lot about it technologically, but behaviorally, if you include the cost of what does it take to educate somebody and convince them, or have them come to the decision that they want to do this, then all of a sudden it may not be so inexpensive.

We also have, as another source of cost uncertainty the highly uneven pace of technological progress. We just do not know in what areas it's going to come and when, just like nobody predicted that PV prices were going to be dramatically lower in the years from 2009 to 2012, but they did come down in a burst, in part because of innovation, but also in good part because of the introduction of China in a big way into producing the panels.

A third source of uncertainty has to do with the pace of linkages that California has with non-California jurisdictions. And those linkages in general are a cost-reducing force for everybody. Quebec is to be inked very soon with us, and that's a small linkage, but an important one. Australia is a much bigger future possibility. And of course there are many others.

So we have a lot of cost uncertainty and, so, in the face of these uncertainties, who has the best knowledge to decide which greenhouse gas reductions should be undertaken and when? And again, the point I want to make is that we will have a whole array of policies to do this, some of those policies will be centralized decision-makers setting standards that all of us must abided by, like New Building Standards; but others of them will be pricing strategies like the cap-and-trade program and greenhouse gas emissions run by the Air Resources Board, and then it's going to be up to individual people and firms that are responsible for turning in those allowances where they want to reduce and how they want to do it. So, again, prices are going to have an awful lot to do with what decisions those people make.

The market allowance prices, most of you probably know, is about $13.50 right now for a current California greenhouse gas allowance, they signal the cost limit for identifying what greenhouse gas reducing actions are efficient; if you can reduce your greenhouse gases at less than $13.00 right now, then that's a good thing to do, and you can sell allowances and make money. If you can't do it for less than $13.00 right now, then you probably shouldn't do it because you can buy allowances for $13.00. And so that price signal applies not just to people using those allowances, but applies to Government decision-makers, as well, who are making regulations that may require people to reduce greenhouse gases. And they, too, need to be thinking about how much does that cost per ton, and is that sensible in light of the cost that we observe in the marketplace.

Finally, let's also make the distinction between short-run and long-run decisions about reducing greenhouse gas emissions. Short run decisions are based on current allowance prices, that $13.50 that I was mentioning a minute ago, but really important decisions are long-run decisions, investment decisions, when people create a new building, or they totally renovate a new factory or a commercial office building, and they're going to be spending in some cases millions of dollars and they're setting up structures that are going to last for 15 to 30 or more years. When those people make long-run decisions, they ask how clean and how green do I want to make my new thing, my new building, my new factory, my new cement kiln, just how efficient and how much do I spend to buy the efficient model? And they think about the cost of buying that model in relation to the expected future price path of greenhouse gas allowances, not just the current price, but what that expected price path is likely to be over the life of the investment. And an efficient long-run abatement is one in which the present value of the allowance savings exceeds the present value of the abatement cost.

So what might the price path look like? Well, the Federal Government has put in a tremendous amount of effort into something that they call the social cost of carbon. They recently -- they issued it in 2010 and they revised it in 2013, and so the numbers that are up here on the chart, particularly the numbers in green, which are the central estimates of this study, are the best estimate of what the U.S. Federal Government is likely to think an appropriate tax rate would be for greenhouse gas emissions, if we had a national tax rate, and it's also what they use in their own regulatory proceedings to value the reduction in greenhouse gases, so they mostly rely on Central Estimate 1, which at the moment with the new estimate, $33.00 is close to what it is right now, that's what it's valuing a ton of reduction of greenhouse gases.

And you'll notice that these green numbers do not go above $100.00 up to $2,050. So there are many kinds of ways that we could reduce greenhouse gas emissions that cost more than

$100.00 a ton, but most of them have to do with reconstructing existing buildings, rather than in new buildings when you can do things much more cheaply from the start, and from the get go.

So one of the things you could see from the study is that, probably not too realistic or too wise, to undertake now certainly in the short-run, in the period of time between 2015 up to 2030, stuff that costs more than $100 a ton. Now, one exception to that which would be an important exception is if you're testing a really new and innovative technology because, for those things, even though it might be very expensive to test them, there can be very substantial learning benefits that we all get in the future and going forward. So I'm certainly not arguing against demonstration projects of innovative technologies, that's not my point. But as a routine matter in terms of what the reductions are, probably ought to be looking most carefully at things that are well under $100.00, and right now that are probably under $30.00.

Let me go on to the point that prices must equal social marginal costs in order to serve as good signals. In workably competitive industries, we don't really think about this; if they're industries without major externalities, and they're competitive, then the prices that come out of them generally approximate social marginal cost. And anybody can just use these prices to compare alternatives and identify the least cost choice. The problems arise when we have sectors that are not workably competitive.

One common failure is the presence of substantial external effects, as when greenhouse gas emissions can be made with no cost or limit to the emitter, which is the case for most people now. Another common market failure is due to the economies of scale that lead to natural monopoly, like our retail electricity distributors. In natural monopolies, marginal costs and average costs diverge and the average cost pricing keeps the natural monopoly whole, but those prices are not good indicators of the social costs. And the electricity sector has both of these problems, both involve substantial externalities and with natural monopoly, and they cause problems with relying upon prices in the electricity sector for calculating the social cost of these reductions.

So what am I talking about? The four

critical reasons why prices diverge sharply from social marginal costs. The first one is that expected future greenhouse gas allowance prices are today unnecessarily low and are deterring important long-run greenhouse gas reducing investments, right now. And we've already gone over the idea that people think about what am I going to save over a 30-year period of time for many of these investments. There's no legislation that ensures that California greenhouse gas reductions will continue beyond 2020. Rational investors will reject in 2015 to 2020 many emissions reducing long-run investments that they would undertake if there was more certainty that reductions are going to continue. AB 32 goes up to 2020, and it doesn't say that ARB is going to go away, but it doesn't say anything about what reductions happen then. The 2050 goal that we have as a matter of law in California is by Executive Order of the Governor, and that can be changed at the whim of any sitting Governor, any time. And so markets do not rely or believe very much in Executive Orders in making multi-million dollar investment decisions. So that's why we need more certainty about the idea of what's going to happen in 2020 to 2030, so that investors will have more sense that the reductions will be required and therefore will pay to make the long-run clean investments that need to get made. And I mentioned that the Air Resources Board could in the Scoping Plan that they're working on right now suggest a process that would lead to legislative approval by 2015, say, of California greenhouse gas reduction goals for the 2021 to 2030 period. And I think if you're interested in California being a good model, you should be supportive of that extension.

Second problem: greenhouse gas allowance prices, due to the global nature of the problem, need to become based increasingly on greenhouse gas reduction costs in a wider than California market. Everybody knows that California cannot by itself solve the climate change problem. What we can do is serve as a good model that might work well if other jurisdictions join in and do the same; but if they don't, we'll have achieved nothing. And if we're all doing this, we could all do it autotically (ph), we could just think about California and look inside and say how do we reduce our emissions from now to 2050, and every jurisdiction, and Arizona could do it, Canada could do it, Australia could do it, we could all do it separately, and never talk to one another about it. But that would be as silly as having a world in which all trade was banned between jurisdictions. There are many many economies that come from allowing people to trade because people have comparative advantage in one way of reducing, as opposed to another. And so that linkage is a force that would be in general driving allowance prices down. We have to be careful to do it among jurisdictions that have adopted comparable goals, or appropriate goals for that jurisdiction. So it's not easy, but we need to work harder and maybe more creatively on that.

COMMISSIONER MCALLISTER: Just a real quick point I wanted to make. The Governor certainly is now on a trajectory to take that message outside of California, when the Chair accompanied him to China not too long ago, and certainly to Mexico and Canada, and neighboring states, the Governor is carrying that message, which is really very exciting, I think, because I think there's a very clear recognition that that is indeed the case, that we can't do it alone, we want to provide some leadership, but it really does require a lot of other people outside of California to roll up their sleeves. And I will ask that you speed it up a little bit because we're supposed to end the session at 2:50, which we're past now, but just so we don't get too far behind.

PROFESSOR FRIEDMAN: Okay, thank you. Yes, sure. I just would mention as a last point on the allowances, that the new Federal initiative may lead to a situation in which each state is given a goal and the states are given a lot of freedom for how they're going to achieve those goals, and many of them may set up cap-and-trade programs, and California may want to think about whether we can link with them and how to do it, it's an important area.

The third of the four problems is that the carbon price signal needs to be in electricity rates and, very quickly, right now we have legislation, SB 695, that presents the pass-through on Tiers 1 and 2 of the residential rate structure of these allowance costs, the extra costs of electricity due to allowances, it's not allowed by SB 695 -- even though the same residences would be compensated by a twice-yearly dividend from the allowance proceeds. And that definitely needs to be revisited by the State Legislature. The essential freeze, just a little bit of latitude, you can raise them by a couple percent, but not very much on Tiers 1 and 2. That represents 64 percent of all residential electricity among the IOU population. So the PUC is in the awkward position that either it puts all the allowance cost on the 36 percent of Tiers 3 through 5, or it doesn't send a signal at all, and the latter is what it's chosen to do so far.

The fourth and the final point that I want to make, and it may be in some sense the most important of the four points, is that retail electricity prices are very far from their marginal costs, apart from the treatment of greenhouse gas allowances, which was my third point. We have this tiered system in which we've totally lost any connection between the actual cost of service and the prices that people pay for that. Almost over 98 percent of California residences are on time invariant rates, and many of those residences pay 30 to 40 cents per kilowatt hour, even in the middle of the night when the marginal social cost of that electricity is generally below five cents per kilowatt hour. And there's a further magnification of this problem because greenhouse gas emissions per kilowatt hour also vary enormously over the time of the day, as well as seasonally, and it's critical to have prices that reflect or signal these differences. So what I'm saying is that the actual cost of service between peak and off-peak periods of time is dramatically huge, multiples of one another, not just percentages but multiples. And we cannot have a system that ignores those differences if we want to achieve our greenhouse gas reductions at a reasonable rate.

There are many parts of the electricity system that depend -- that have not taken off yet very much, and in part the reason they haven't is because nobody is on time varying rates. Vehicle electrification itself, if people were charged the social marginal cost during the off-peak period, it would be a lot more popular than it is right now, even the special rates that exist for electric vehicles have these weird things where many people end up paying 20 cents or more per kilowatt hour in the middle of the night with special EV rates.

Demand Response participation, again, what people are paying, the average cost rather than the peak period rate, they don't have very much incentive to participate in Demand Response programs, but if they were paying the peak period rate, they have a lot more incentive.

Storage itself, which other speakers have already talked about, storage itself only has value when there's a price difference between the price you pay to charge up the battery, if it's a battery, and the price that you receive, or the avoided cost when you use the battery. In Germany, where time of use rates are prevalent and there are big differences between peak and off-peak periods, it's common to see people in their offices, they have these storage batteries that get charged up overnight and they run their computers and other stuff during the day, and it's because they're facing much closer to the correct marginal cost of what it means to make electricity at night and make electricity during the day.

There are many options for how to switch people onto a time varying rate. My favorite one is called HOOP electricity pricing, there's a proceeding going on at the Public Utilities Commission right now to consider reform of residential rates. The one I like is called HOOP pricing, it uses volumetric rates at time varying marginal costs exactly, and it separates out the fixed costs of the system and raises them by graduated annual connection charges. This seems strange in the electricity industry, but if you look at another industry like the cell phone industry that has -- it's an all fixed cost industry, they use these graduated fixed fee things all the time. Here's an example on which on the left we have actual AT&T charges where people sort themselves out into buckets by minutes per month, and the second column is the monthly fee that they pay, and the monthly fee increases if they are in a bigger bucket. And I want to do the same thing with our electric rates. I want people classified by their annual kilowatt usage and households zero to 2,000, 2,000 to 4,000, 4,000 to 6,000, and the monthly fees that you see on the right are calculated by a simple formula that's in a paper of mine, it's available on my website, it's referenced right here on this diagram, you can look at it later, it's for a system in which everybody between 2:00 and 7:00 p.m. pays 30 cents a kilowatt hour, off-peak they pay five cents a kilowatt hour, and these are the monthly fees that raise exactly the same revenue that the IOUs are collecting right now. Now, I think this is a good idea, but we have to watch out, there's legislation pending right now, I think it's AB 327 in the Legislature, which began, I think, in a very promising way to give the PUC more latitude than it has had in setting rates, and fixed things like, the 695 problem that I mentioned before, but somebody has inserted that there can't be more than a minimum fee connection charge of $10.00 per month. I hope that won't last because it prevents having a progressive or a proportional system that's like what we observe in the marketplace and is much fairer for anybody. So let me just mention that. Okay, I've run out of time.

So again, just to summarize my four

recommendations, the State needs to confirm a credible commitment to the continued reduction of greenhouse gases beyond 2020; the State needs to give more emphasis to expanding partnerships and linkages; the carbon price signal from greenhouse gas allowances needs to be made visible to retail electricity customers; and there must be much more widespread use of time varying retail electricity rates based on marginal costs. Thank you very much. The details for this talk are contained in the study on the *Next 10* website, but the opinions are only mine, not any organization with which I'm affiliated.

COMMISSIONER MCALLISTER: Thanks very much, Lee. Thank you very much. We really appreciate your bringing your expertise here today. I guess just a couple observations. You know, in your consequences of retail electricity prices unrelated to marginal cost, I remember the CSI as kind of what I wanted to say, when the solar initiative was first rolled out, you know, and net metering was relatively untested, it was relatively new, at least in the solar realm, and there was a requirement in SB 1 that actually said anybody who got solar would have to go on a time of use rate, and it turned out that there were some distortions, particularly down in Southern California inland areas, but it turned out there was emergency legislation needed to sort of repeal that requirement for the moment, and it never came back. And so, you know, we definitely have to be careful to transition nicely out of any existing scheme into some new scheme, and I think that's pretty clear and you essentially said as much.

Also, I would just harken back a little bit to Lorenzo's presentation, let's see, one of the ISO presentations, just about the -- you could make the same argument about the need for real time cost tariffs at the wholesale level, as well, and there's kind of the whole problematic about how do you allow the wholesale and the retail to meet up, how do you design that into the system? And that's a whole different question, so not meaning to throw cold water on it, I think it's absolutely true that we need better price signals to come to customers within certain equity boundaries and that kind of thing, but I really appreciate the way you've laid it out and look forward to reading up some more on this.

And then finally, we have so much great technology today and the cell phone industry is just front and center every time you get the bill, you don't even have to get it in paper, you know, you get it online, and if you want to know what call you made at 3:00 a.m. on September 2nd, you can go look at it, and you know what number it was to and how long it lasted and what it cost you. And I think that that kind of immediacy of feedback to customers would allow them to exercise their sort of natural tendency to want to optimize in some sense. I mean, not all customers -- we have all these issues around marketplaces, right? We have information asymmetries, we have lots of principal agent problems, I think there's a lot of things that do get in the way in terms of transaction costs that you didn't really mention there, but you know, having better signals can't be a bad thing and so it doesn't solve the whole problem possibly, but it certainly is a good step in the right direction, so thanks for the analytical approach.

CHAIRMAN WEISENMILLER: No questions. Thanks.

PROFESSOR FRIEDMAN: Thank you very much.

MS. KOROSEC: All right, now it's time for us to move to our afternoon panel, so I'd like to ask the panelists to come up to the table if you don't mind. We've got name tags for you so our Court Reporter can keep track of you during the spirited conversations that will no doubt ensue. Our two IOU representatives will have a short presentation to begin with, and so you can either sit in your chairs and have me run your slides for you, or you can come up here to the podium and run them, as you prefer.

MR. WILLIAMS: Yeah, it might be more fun -- I'm Ray Williams from PG&E, by the way -- it might be more fun if I gave Edison's presentation and Dhaval gives PG&E's, but I guess we won't do that today.

So I'm actually going to introduce a concept and take kind of the broad view that Lee Friedman did, and I'll try to move through these slides as quickly as I can.

So what I'd like to talk about is just to introduce this notion of a carbon metric framework that may tie some things together that have been talked about in a much deeper level today, focus on that, but also talk a little bit about linkage, CHP, and GHG reductions, and cost containment.

PG&E and AB 32, we've been a longstanding supporter of the legislation. I've been involved personally in the latter stages of that legislation moving through the Legislature in 2006. We support AB 32, we're implementing the measures. We believe that California should adopt a multi-sector approach toward clean energy policies going forward, and we support a rigorous and transparent cross-sectoral analysis.

I'll also say that you'll see our little Venn Diagram up there, we have one portfolio on the supply side, but three objectives: system reliability, affordability for customers, and low environmental impact; it's a tricky balance.

So I just wanted to introduce this notion of a carbon metric framework. The idea is to have something that's maybe not easy in terms of its analytics, but simple and transparent in terms of the ability to look at measures within the electric sector, the electric sector and transportation sector combined, and also, because of the way we constructed it, to look at program-based measures versus market-based measures. It can also hopefully be a tool that you could use for looking at post-2020 greenhouse gas policies. It's a very simple construct, the cost of emissions reductions are shown as dollar per metric ton, it's net cost less -- divided by emissions abated, and I'll get into a little bit more on the next page about how we constructed it.

So what we looked at here, what we adopted after some discussion, was something like a total resource cost test, and so we looked at benefits that could be monetized in the relevant market, whether it's the energy market, or the transportation market, and we looked at that less the cost, the full project cost including capital and operating costs.

In terms of emissions included, we looked at what could be reduced or avoided at the burner tip, or at the tailpipe, to keep them equivalent. On transportation, we also looked at it on a well to wheel -- what's called a well to wheels basis, and from that, where relevant, we subtracted the carbon created, and that's relevant both for the Low Carbon Fuel Standard, as well as for CHP. So what we do with this kind of a construct is we make it as clear as we can what costs and benefits are included, and which are excluded, and that everything is transparent. This particular construct where you're really looking at what's monetized as opposed to social costs helps you look at the cost of the program measures, but also related to a cap-and-trade market because essentially you've included and excluded the same costs that would be included or excluded when looking at allowance prices or a carbon tax.

Now, this is not to say that what's excluded is not relevant or important, we think that certainly it is, certain of these are more important for certain program measures versus others, and I'll talk about later how you bring that into the picture.

These next two slides show how we sort of grouped the results into three categories, this is conceptual, and then next we'll talk about what you might do with them going forward.

So what you see here are three circles, three ovals, green, yellow and red. And essentially what we did here is we looked at the cap-and-trade prices in the AB 32, so as some of you may know, there's a floor price in the auction reserve, which starts around, I think, $10.00 or so, it's about $14.00 in 2020, that's in 2010 dollars, and so it would be a little bit higher. So that's a nice delineation for what really should be cost-effective almost without carbon.

We also looked at the third tier of the allowance price containment reserve, that's $66.00 in 2010 dollars or, to avoid some confusion, roughly $77.00 or $80.00 in 2020 dollars. So we tried to not only, by including and excluding certain costs, but by looking at what the Air Resources Board has in terms of a floor and ceiling, take these program measures and group them into these three categories. And it's important in terms of how you might deal with these going forward. We did have some initial results where we looked at the year 2020, and we looked at the program measures in the electric sector, namely electricity and natural gas energy efficiency, we looked at offsets, and we also looked at Renewables Portfolio Standard going from 20 to 33 percent, and we looked at the cost of the Low Carbon Fuel Standard. We had E3, Energy and Environmental Economics, help us with the Energy Sector Analysis, and we had ICF help us with the Transportation Sector Analysis, and an offset verifier, DMV, who helped us with offsets. And these results initially showed that electric energy efficiency is clearly quite cost-effective, there's probably more available on paper that's cost-effective beyond what's included in the AB 32 Scoping Plan.

We also found for natural gas energy efficiency it's quite cost-effective, but there's probably a limited amount available beyond what's in the ARB Scoping Plan. So possibly quite a bit of promise in terms of electric energy efficiency. So that's what looks inexpensive to us, at least on paper.

Moving to the yellow oval, here this is more moderate costs. This is where offsets begin to look cost-effective, as you might expect; you introduce a carbon price into electric and transportation, or into anyone who is covered by a cap-and-trade program, and if you can buy offsets at $15.00 at a cap-and-trade price, your expectations about allowance price happen to be

$30.00, then offsets become attractive and it becomes a way of getting real reductions, but also moderating to the cost of California to utility customers.

Moving into the pink area, those are ones that we found to be expensive, but it might be no surprise that includes the Renewable Portfolio Standard going from 20 to 33 percent, those clocked in at around $150 to $200 a metric ton. We did it on a delivered cost of energy, which means we included the technology costs, a balanced plan cost, the integration costs, then I would say, in a not very sophisticated way, and also incremental transmission.

For the Low Carbon Fuel Standard, on a scenario basis, we had costs that came in in the $100.00 to $200.00 per metric ton range, so those also were expensive. I will note that the Air Resources Board is looking at design changes to the Low Carbon Fuel Standard, and those design changes, which I think will be taken up next year, can reduce that cost from $100.00 to $200.00 a metric ton.

Okay, so in essence what I'm trying to do with this approach is to have something where you can compare costs across program measures, you can compare across sectors, and you can also compare command and control measures to market-based measures, that's the visibility that we were trying to create with this kind of approach.

Okay, so what might you do with this going forward? So again, you have the same three categories, the same color scheme. If a program measure such as electric energy efficiency comes in below the floor price, you might consider that to be cost-effective, you might prioritize implementation or look for ways to realize what you see on paper as additional GHG energy savings benefits. If you're in the yellow area, these may be cost-effective today -- Lee talked about a price of $13.00, it could be $13.00 or $30.00, whatever the price might be. This is the category that offsets falls into, these should be prioritized after Group 1, and once you explore the likelihood of a cap-and-trade price signal, or a carbon tax, whatever it is, in California right now it's AB 32, a cap-and-trade market, that that market can help improve the economics and make these cost-effective. So you need to look at the interaction here between the market itself and what else you might need to do.

So if a price comes in above the third tier of the reserve -- and the reason why I chose that number, by the way, is there was an ARB Board Resolution which requested that the staff itself ensure that the price in a cap-and-trade market does not exceed the allowance price and it's embedded in the third tier of the APCR. So for convenience, it was a Board Resolution, they drew a line there for market-based measures, so I'm using it here in looking at various program measures.

So the idea here is not that you need to exclude or stop, but there are actually some things that Lee had mentioned earlier which I would also reinforce, and that is you want to ensure that the actions that you might look at, which initially might be quite expensive, there's a possibility of achieving market transformation, getting cost reductions, and getting significant abatement from that activity. So you have to just essentially ask yourself a few different questions than you would in program measures that might fall in the first categories, or initiatives that might fall in the first category or the second.

The second is, let's go back to societal benefits, we can look to see if societal benefits outweigh societal costs, so if you go back to page 5 where you see all the elements that I excluded, if things come in at a very high level, just looking at sort of a market-based, or what can be monetized kind of approach, and it doesn't look cost-effective, then this might be a time and it may be more efficient to bring in those societal costs and benefits and see what that picture looks like. Okay?

Also, you'll find that we're concerned about the cost to utility customers, and to the extent that you have very expensive measures, particularly early on, we would hope that we could be looking for funding sources, at least initially, that were not utility customer rates, they could come out of Federal Government funding, or AB 32 cap-and-trade revenues, or private equity -- green private equity, and there may be other places to go, it would be good to explore other places to go besides utility rates.

Okay, shifting topics, linkage. Linkage is good. Maybe we don't need to be sold too much on that. You know, and the easy example is the electric sector is about 100 million metric tons per year in terms of emissions, and 80 percent reduction is essentially an 80 million metric ton reduction. That's not a lot in the grand scheme of things and clearly if we're not an example for others, we haven't really accomplished very much. So I don't think I necessarily need to go through too many more of these bullet points, I think maybe they're quite evident. Certainly the Air Resources Board is very active in terms of finding ways to link with other jurisdictions, and apparently so is the CEC.

I want to talk a little bit about CHP, and Bob knows - I'm sorry, Chairman Weisenmiller knows way more about this topic than I do, but --

CHAIRMAN WEISENMILLER: But I was going to say, but you walk into it each time on start-up and --

MR. WILLIAMS: I'll walk into it every time, I'm just a very slow learner that way. So just talking about CHP with respect to when does it and when might it not reduce greenhouse gas emissions, that's the question. In order to answer this question in a rigorous way, you need to define the appropriate metric, which is separate heat and power, which includes, as you see on the Y axis, the efficiency of a boiler, and on the X axis, grid electrical efficiency at the margin. So, in essence what this line does is it delineates resources which can reduce CHP, which would be in that upper right quadrant, and resources which may decrease CHP, which would be in the lower left quadrant. And again, this benchmark relates only to natural gas topping cycles, CHP. I think it's pretty evident that bottom cycling CHP or renewable CHP does reduce greenhouse gas emissions.

So why is this line important and why does it need to be carefully drawn? If you go to the next page, you can see there are three lines here, the first you'll see a dotted line to the left of that red line right there, that is an average emissions for U.S. Grid, and is clearly higher emitting on the grid side because there's coal in the mix on the margin, not just natural gas. And there, if you look at a series of dots there which represent different technologies and different operating efficiencies, in that particular market, or in that context, CHP is greenhouse gas reducing because it's to the right or the upper quadrant, you might say, relative to that line. If you look at the red line, which is the same as was on the previous page, you'll see that GHG or CHP facilities, again, different technologies, different assumptions about operating efficiencies, are on both sides of the lines. So, in essence, the message here is that you really have to look very carefully at the market that you're looking at, and you have to look very carefully at the technology and the operating efficiency of CHP facilities in order to make an appropriate comparison.

And you'll see on the right, that's essentially taking the same line here, but giving credit to 30 percent RPS. This is shown in an ICF study, I believe, commissioned by the CEC. I'm not saying I don't think that's necessarily the right metric, but I just show it there for reference.

CHAIRMAN WEISENMILLER: Yeah, but as I said, I think the technical analysis represents PG&E's litigation position on these issues. Certainly if you had Jim Ross or someone else to do the double-hump, or even the net heat rate type of number, to take in account start-up and no load, you would really shift that. Having said that, we really really really need to focus on getting the bottoming cycle stuff going. Now, as you know, there was that one project you guys held up for five years on interconnection stuff that was a bottoming cycle, so we really want to see progress there, also renewable CHP, and certainly any wastewater treatment where you could be reducing methane emissions.

MR. WILLIAMS: I hope that Sam Rick (ph) is moving along well.

CHAIRMAN WEISENMILLER: I'm hoping there's no more hang-ups like that.

MR. WILLIAMS: I will say, I obviously represent the procurement side of PG&E, and in our last RFO we made phone calls encouraging through the various CHP trade groups to bring bottom cycling and renewables CHP to our RFOs, and we'll certainly take a close look at what we get through those RFOs.

CHAIRMAN WEISENMILLER: That's good.

MR. WILLIAMS: Okay, so let's -- I'm going to focus here back on the electric sector. These analytics are a little bit out of my area of practice, I focus on CHP, which is why I continue to have this conversation with Chairman Weisenmiller. Also, CCA, as well as GHG, but I'll talk a little bit about this. Obviously, one of our three objectives is to maintain reliability and we are very focused, in part because of the illustrations provided by the duck graphs, and much of what you heard here today, on flexible products and attributes, in terms of how we would like to think about procurement going forward is to look at the product or the attribute, how much do we think we need given the change or the increasing penetration of renewables over time, and have the ability from a procurement perspective to select the lowest cost alternatives on a product or an attribute basis, and so this is just a conceptual curve, it's not necessarily meant to rank order these various ways where flexibility could be brought to the system, but the notion is from a procurement perspective it's better not to have -- it costs less to our customers to minimize technology set asides where we can do that, and to bring these attributes in to one procurement proceeding if that were possible.

You know, we prefer moving towards market-based measures to the extent that we can, and we hope that the carbon metric framework that we've shown here can help with that, and can help improve the visibility between program measures and market-based measures. We really encourage and will certainly support seeking and taking advantage of expanding GHG reduction initiatives to work with other jurisdictions. We also need to think about the costs to our customers, and that's a responsibility that we have as a utility, and to think about, if other entities are not joining us, what kind of economic disadvantage that may place the State under, what the cost might be to our customers, and figure out where to go from there.

So again, from a California perspective, I think these three objectives are all important. You know, looking at reliability and low environmental impact, those two, it's very difficult just to solve that problem, but I think it's really important that we bring affordability into that picture and to really think about a way to look at this in a systematic way where costs are part of the picture as we move down this road. I think I'll stop there. Thank you.

COMMISSIONER MCALLISTER: Thanks very much. Just one sort of broad question. It seems -- so this framework obviously, there's a lot to like about it, I mean, you have to pay attention to all of those things, and I think you won't find a whole lot of disagreement about those three overlapping goals. I guess just, you know, there is some urgency here to kind of get this done and I guess I would just ask about things like, okay, well, if you're going to be asked to do something, and then there's a whole -- say it's Demand Response, or it's this sort of procurement of a certain kind of resource, you know, it seems to take a really long time just to work out the nuts and bolts of how it's going to work, you know, even just the basic things like cost recovery, how you guys are going to get your cost recovery, that can take a couple of years. So how sort of might a collaborative partnership that you've alluded to here kind of function to move it along relatively quickly so that the bottleneck kind of isn't there in the near term? It's a very broad question, I acknowledge.

MR. WILLIAMS: I will say, you know, we

do have an energy resource and recovery account and we're looking at about a billion dollar increase from 2013 to 2014, so that's an important issue, I think, for us. Roughly half of that is associated with greenhouse gas, the 2013 costs that we incurred as part of the cap-and-trade market, and the next -- the incremental amount of renewables that are coming in in 2014, and these are from fairly expensive contracts that were negotiated back a few years ago. I would say, though, to get people to talk to each other, so to Air Resources Board and the CEC and the PUC maybe to take to each other more, it's great that you have the ISO here and thinking about these problems, and to talk in a collaborative way, like most of these workshops are. But also what I'm trying to promote here is a transparent set of analytics so that the framework is easy to understand. The data that we used, we took a statewide perspective, it was a condition of working with the two consultants, the two primary consultants, E3 and ICF, that they used public data, and that they make their reports available for anyone to look at. So, you know, good transparent analytics, a framework that everyone can follow, and just good communication between the agencies. We've been talking a fair amount with SMUD recently, they have some good ideas for us, hopefully we have some for them, as well.

COMMISSIONER MCALLISTER: So just one final question. Was this something that PG&E sort of took upon itself to do and contract ICF and E3 on? Or was there some PUC order to do this, look into this issue? Or I guess what's the origin of this particular effort on your part?

MR. WILLIAMS: This work was my idea, you could say. It was done -- it wasn't done pursuant to a PUC order, it was done really to help us engage in the -- originally to engage in these Scoping Plan updates at the Air Resources Board, which needs to be done in 2013, you know, this is the reason we included offsets, this is the reason we tried to bring in a transportation measure to help show that this kind of a framework could work across sectors. But in essence, it was done to help us with the AB 32 Scoping Plan Update. But, you know, we're here to share it with anyone, and hopefully in some form or another the agencies will take it up and maybe it can help with the coordination between agencies, and help us find a lower cost solution overall.

COMMISSIONER MCALLISTER: Yeah, I think that's something we do reasonably well. So thank you very much, appreciate it, and let's keep it moving and have Edison's presentation, and then hopefully have quite a bit of time leftover for the panel.

MR. DAGLI: Good afternoon, Commissioner McAllister, Chair Weisenmiller, Energy Commission staff and the workshop participants. Thank you very much for this great opportunity to offer a few thoughts on this important topic.

Over the next few slides, what I would like to quickly touch upon is some Edison involvement in future infrastructure need assessments, some future industry trends. I want to briefly talk about a current Edison effort to focus on the reliability aspect of preferred resources. I also want to take this opportunity to raise a few questions related to future industry evolution and the business models supporting that, and then I also want to quickly touch upon the rate structure issues.

So one of the things I wanted to point out is there are many forums currently in play, there are a whole host of different infrastructure need assessments that are being looked at. Some of the examples we have listed here, the most prominent one is the PUC's LTTP Proceeding, the three separate tracks that are looking specifically at what sort of infrastructure need exists in light of various changes occurring very quickly and somewhat suddenly to the electric system, especially in Southern California. I mean, one of the tracks has already yielded a procurement mandate for both conventional and preferred resources. Another two tracks are currently underway, one of them looking at additional infrastructure need to integrate renewable resources pursuant to 33 percent RPS, and also additional local reliability need in both SCE and SDG&E areas in light of the retirement of SONGS that was announced in June, earlier this year.

I also want to touch upon the CAISO's transmission planning process, which is another robust forum to evaluate a variety of different future scenarios and identify transmission grid development opportunities for both reliability and efficiency. And then, you know, you are very well aware of the Desert Renewable Energy Conservation Plan, which is once again an important forum to evaluate infrastructure needs in light of the State's preference to reduce greenhouse gas emissions.

So this is just a snapshot of what's happening today and similar activities will continue to occur; so long story short, one of the questions the Commission staff had asked, you know, what sort of tools and models are needed, I simply wanted to point out that there is a robust forum out there which does look at various simulations models, various demand forecasts, various supply scenarios, etc., and tries to come up with plans that utilities can act upon in order to ensure that the system infrastructure stays intact to deliver reliable, safe, and affordable electricity to the State's consumers.

Moving on to some future industry trends, this of course is not based on any detailed analysis, nor as Chair Weisenmiller had remarked, is it based on astrology, this is just an effort to articulate some observations that we see currently underway. So we at Edison believe that over the next 10 years, especially in Southern California, the focus will continue to be on maintaining the local area reliability in light of some of the infrastructure evolution that's currently going on, primarily the phase-out of once-through cooling, also in parallel of aging infrastructure retirement, including aging power plant retirement, then the retirement of San Onofre that has made a lot of news. Simultaneously, we do have a lot of renewable resources that, like Ray mentioned a few minutes ago, were signed several years ago, but they are mostly coming on line now, and so the need to integrate those renewable resources is upon the various utilities and that effort is also resulting in a lot of infrastructure requirements, both on transmission side, as well as a need to have sufficient flexible resources to integrate those resources.

Over and beyond the 10 years, meaning over the next 10 to 20 years, we believe, or we at least envision, a potential to see a much higher level of distributed energy resources, mostly interconnecting at distribution level. This is a trend, you know, I'll talk about it a little more, but that has the likelihood of completely changing the utility business model that exists today, which is really to take a product that is created at a central power plant, use the pipelines or transmission lines, if you will, to deliver it one way to the end use customer.

Second, a potential trend over the next 10 to 20 years is an increased penetration of various forms of transportation electrification, not just Battery Electric Vehicles, or Plug-In Electric Vehicles, but also other forms of transportation electrification, which, even though it was discussed earlier this afternoon that may or may not turn out to be a very large portion, but even if it is five to 10 percent of load, I mean, that is pretty sizeable in terms of electricity demand, especially when the current projections show it's not going very significantly.

And then lastly, over the next 10 to 20 years, it's very likely that advanced technologies such as energy storage will be much more available and affordable and will become a much larger part of the electric infrastructure.

Beyond that, 20 to 40 years or beyond, I think there are open questions about whether the primary form of decarbonization will be through large central station renewable gen, paired up with bulk transmission, and/or a vast number of smaller preferred resources which are mostly at the distribution level. This is an important criteria, I mean, depending on which becomes more accepted, or more of a norm, it does have a very different impact on the electricity infrastructure and both grid operations and utility business models as we see them today. Of course, as I noted here, land use issues, intermittency, over-gen, all those issues do need to be addressed in either scenarios because, regardless of whether it's large central station, or localized, we are looking at intermittent gen, which will create most of these issues. Hopefully, advanced technologies will be available to mitigate those impacts, and as other speakers have mentioned before, especially Lorenzo touched upon that quite a bit, distribution circuits may evolve into smart microgrids at the local level. So all in all, industry trend is pointing to a very different future than what has been the case for the past 100 plus years.

This is just a very brief, you know, making you aware type mention of an Edison effort that we have recently undertaken. We first discussed that in the LCR, or Local Capacity Requirement Procurement Plan that we had submitted to the PUC not too long ago, and then in testimony that we will be submitting shortly related to the replacement infrastructure requirement in light of SONGS' retirement, we plan to discuss this some more. And, of course, whatever is not covered in both of those areas, we will probably reach out to the PUC on a standalone basis. The basic intent here is to have a paradigm shift in procuring preferred resources. What we have observed is most of the preferred resources procurement today happens to, you know, satisfy individual compliance targets or mandates without a whole lot of attention paid to the reliability impact of that preferred resource acquisition. And so Edison, what we would like to see is to start a dedicated focus on better measurement, assessment and improvement of the preferred resource acquisition strategy so that we understand their attributes better, you know, what they can do to help with reliability and essentially, you know, try to acquire preferred resources in a strategic way where not only do they help with reducing consumption or making consumption more energy efficient, but also help maintain or improve the grid reliability.

Currently, preferred resources tend to require a corresponding response on maintaining the reliability, by additional flexible resources, etc., so this in part will hopefully help mitigate some of that additional need. You know, the bottom line here is we would like to develop a balanced portfolio of both supply and demand side resources, demand side preferred resources, and that we can essentially count on to provide performance attributes while also achieving social objectives.

So here is the most interesting part for today's presentation. These are some questions, and I don't necessarily have any answers, but questions nevertheless, important to discuss, with especially this group of people because some of these questions are relevant to the future policy.

By the way, this no means is an exhaustive list, I've tried to cherry pick things that appeared to be relevant and important enough to start addressing them now. So first question: A lot of the discussion today has inevitably focused on a need for a whole host of different types of infrastructure, whether it's Smart Grid type features, integrating better distributed gen, measurement, and other type of metrics, but requiring some dedicated infrastructure, as well as things like electric charging stations, etc. Question is, both the generation side of the investments, load management side of the investments, as well as infrastructure simply to maintain reliability and to integrate those investments, how will they occur and be paid for? I mean, are these investments regulated, unregulated, or a combination? And are they happening, you know, which we would prefer, which is through markets, or are they likely to happen through mandates? If they are to happen through markets, what is the mechanism to start working on developing such markets so that they're ready when the society needs them to happen?

Second question here, in a highly distributed gen world, as anyone can imagine, the end use consumption that is metered and built by the utilities is going to reduce quite a bit; in that event, if volumetric rates may or may not be the most palatable way to get compensated for the services that a utility provides, I mean, what is the way that a utility is going to receive its fair compensation and cost recovery for the services it will likely need to continue to provide, especially to support the localized resources? Similarly, if a future, whether it's 2030 or much beyond that, nevertheless, if that future includes a significant number of plug and play, I mean, I think one speaker mentioned a refrigerator-sized storage device in each home, or something like that; well, if that's the model, once again, how will the utility ensure the reliability and safety of that service when, you know, they may or may not be directly involved in installation for monitoring of those plug-and-play type both supply side and demand management side devices? And similarly, will the utilities have to invest in costly and long lead time distribution circuit upgrades just to make those devices, you know, workable in small distribution circuits. If so, once again, key question: how would the cost recovery work? Who will pay? And how?

Lorenzo talked a lot, and I don't want to replicate this, but once again, the system operation and bulk system interface issues will be key to answer, I mean, how will the distribution system interface with the bulk power network? And if an Independent System Operator is still on the hook to maintain the reliability of the system, will they be able to rely on those distribution level resources? Or will they see a need for back-up flexible central station capacity just so that there's no reliability issues?

The last topic I want to touch upon here is the rate structure. Under the current rate design, the tiered rate design, as well as the net energy mirroring rules, it's just a fact that an increasingly smaller number of customers are now bearing the utility's incremental costs. This is not a sustainable outcome, I mean, this does not, 1) make a cost allocation fair, nor does it provide the right signals for wide adoption of some of these technologies. I mean, net energy metering currently allows customers to avoid paying the utility's fixed costs, including the costs associated with reliability connecting that very same customer to the grid. And similarly, under the flawed residential rate structure, high usage customers are able to reduce their bills far far above their actual avoided cost. So the difference is, both with the costs of connecting that customer to the grid, as well as maintaining that customer's reliable service, as well as the payment that's above what it costs, I mean, that delta is then borne by the remaining customers. I mean, this is essentially not a structure that will work if we are looking far down the road at 2030 and beyond.

I just wanted to mention here that, at the PUC, the PUC does have a proceeding to look at the residential rate design, and Edison has made proposals in that proceeding for increased fixed charges and flattening of tiered rate structures.

Just some concluding thoughts here. You know, as we mentioned, especially in context to the preferred resource pilot, we at Edison do see a need to develop balanced portfolios. We need tools and metrics to assess the reliability of preferred resources. We don't see them currently being effectively used and we see a need to create such tools and metrics if we are to try to avoid reliability issues with increased penetration of preferred resources.

We also believe that policymakers need to assess and honestly discuss the reliability and safety risks involved in the policy preferences that they will put in place today related to future electricity infrastructure. And then, lastly, you know, we believe the industry model, the framework, is on its pathway to change, fundamentally, if some of the trends that I mentioned earlier do come true, and the challenge is to make sure that the industry framework and business models are evolving to a sustainable end state, which are not only going to provide the right level of safe affordable and reliable electric service to consumers, but also yield desired policy outcomes.

So those are all the remarks. On the last page, this is a schematic of a Smart Grid Demonstration Project that Edison currently has underway in Irvine, just for everyone's awareness. And that concludes my remarks.

COMMISSIONER MCALLISTER: Thanks very much for your remarks. I think we do need to move into the panel because we're a little bit behind, and we're kind of shortchanging them a little bit, and also we have public comment afterwards, so I won't ask any questions at this juncture.

CHAIRMAN WEISENMILLER: Yeah, actually what I was going to do was just frame two questions for the panel based upon -- one of them was certainly anyone who wants to comment on ways to make the utility business model more viable, that would be interesting, and in terms of the changes we're looking at; and the other one is, to the extent that, you know, the utilities are talking about some sort of fixed cost recovery -- I know I always think of it in terms of what do we get back in terms of are there specific elements of an investment plan in terms of a smart grid that, you know, we can try to convince the customers that they're getting value for that charge, certainly those are two suggestions at least for overarching questions. Obviously, they're suggestions, I'm sure you have other things in mind.

MR. VIDAVER: Commissioners, may I ask a favor? Mr. Webster of LADWP had hoped to participate in the panel and he has a plane to catch, but he was hoping to be able to respond to a comment made during public comments before lunch, if he might address you briefly?

CHAIRMAN WEISENMILLER: Sure. An early public comment.

MR. WEBSTER: All right, thank you for the consideration, but the question that I wanted to respond to was can't we just go ahead and eliminate all of our ocean water cooling plants and replace them with something different. And I made the comment that we really needed those for support of our electric grid, and here's what I really want to stress, is that our transmission system is built such that these local plants actually support the transmission without them is that we run the risk that that transmission would actually sag, melt, especially if there's a contingency. And the only way around not having these coastal plants is to build transmission that comes into the southern part of the grid and supports it, and I don't know how we actually get rights of way to do that, come through the ocean, come through neighborhoods, but for us, because of the way it's built, we absolutely must have generation there.

Now, with that comment said, it doesn't mean that we actually have to run those plants all the time, it means we need that capacity start-up quickly and by transitioning from these older technologies, we have to sort of run them all summer so that they're there available, with gas turbine technology we'll actually be able to just know they're there and be able to start them up quickly. So while the capacity factors are very very low, it's the capacity that's really needed. So I wanted to respond to those comments from the Sierra Club, and I just wanted to hit that directly, that we don't see any alternative around having this generation locally to support the transmission system. All right, thank you for the opportunity.

COMMISSIONER MCALLISTER: Thank you. So

any particular -- well, David, you're going to moderate?

MR. VIDAVER: When I was a student at Berkeley, one of my professors told the class "I can make all of you pick up a pen and write one dot on a piece of paper," but I notice that the Chairman has that ability, as well. It's perhaps -- you recall there are individuals on the panel that have not had a chance to speak today and may want to speak to what they've heard. We have Sierra Martinez of the Natural Resources Defense Council, and Matt Vespa of Sierra Club, and Laura Wisland of the Union of Concerned Scientists. So if any of you would like to have a Powerpoint-free opening statement, go for it.

MR. MARTINEZ: Sure. So thank you for inviting us onto this panel and thank you, audience, for sticking with us through to the end. My name is Sierra Martinez, as Dave mentioned, and I'm representing the Natural Resources Defense Council. We represent our 100,000 members in California here and our main concern is the environmental impact of our dependence on energy consumption.

I want to start off by commending you for having this conversation here in the IEPR forum, I think it's the right forum because it takes care of this statewide perspective. I think it's important to have it here, as well, to have it early, we can't be having these conversations early enough.

In thinking about the substantive issues raised today in how we're going to meet our 2030 and 2050 goals, I think it was clear from everyone's presentation that there will not be any single technology that solves our problems. This is going to be a portfolio of technologies and a package of policies. So the Energy Commission, I would recommend, taking concrete actions after all these conversations in the form of studying various scenarios, including aggressive scenarios. Some of the topics that were raised today, I want to make some brief comments on. Flexible generation: a lot of people are concerned with this, and rightly so; however, we should make sure to study the embedded flexible capacity in our system at the outset before setting up procurement mechanisms to arrive at the need for new flexible capacity. At the FERC technical conference the other month, TURN presented slides on various estimates of how much flexible capacity actually is embedded in our system. One particular place that might be interesting to study would be in hydro-pumping. About one-fifth of the State's electricity consumption is used by moving and treating water around the state and the ability to pump at different times during the day could alleviate the need for flexible resources going forward.

I can't highlight enough the importance of energy efficiency in reducing our need for flexible generation. People often think of energy efficiency as sort of a baseload demand-side resource, but different energy efficiency measures can reduce energy consumption at different points in the day, and you can get different load shapes. For example, residential lighting efficiency measures are going to be producing the bulk of their savings during the 4:00 p.m. to 8:00 p.m. timeline that we see so pronounced in that duck curve.

Last, there's been a lot of discussion today about the costs of going forward and meeting our 2030 and 2050 greenhouse gas goals, but none of them are larger than the cost of doing nothing. We're engaging in an experiment with the earth's atmosphere and the consequences are untold, and therefore the Energy Commission should go forward in making aggressive scenarios the focus of its further studies. Thank you for the opportunity.

COMMISSIONER MCALLISTER: Thanks, Sierra. I will second what you said about lighting -- huge opportunities in lighting in existing buildings and all of its tape.

MS. WISLAND: Should we just go around? Or do you want questions?

COMMISSIONER MCALLISTER: Yeah, that would be great.

MS. WISLAND: Okay. Hi, good afternoon. I'm Laura Wisland with the Union of Concerned Scientists. I work in the Claimant Energy Program in our Berkeley Office. Thank you so much for the opportunity to speak, thanks to the audience for sticking with us. I first want to say that I really appreciate the CEC putting on the table 2030, I think it's high time we start talking about what this should look like, actually NRDC, UCS and Sierra Club have all worked together on the Long Term Procurement

Planning process with the PUC, trying to use the LTTP as the place to start looking more long term, and so far they haven't been willing to do that, so we really appreciate the opportunity to have this discussion. I think the CEC is a good venue for this because you're looking at the IOUs as well as the Munis, so it's really important.

And there's been a lot said today, there's a lot to digest, so my comments are kind of big picture, and then some specific real time reactions to Edison's and PG&E's presentation. I'm hoping that throughout the course of this year we'll have an opportunity to drill down on some of these issues a little bit more and talk more specifically about Demand Response potential in different areas, storage cost assumptions, those sorts of things that were touched on at a very high level.

So the first thing that I want to say is that I was really glad to hear the Chair bring up issues concerning climate change and its impacts on the electricity grid because we're obviously beginning to see this, and the Energy Commission really has been ground zero for some really important research on this issue, and I really hope that that continues. And I hope that, as we start to look through different scenarios for 2030, that you can help us connect the dots between the great research happening in other departments at the CEC on this issue surrounding how our different electricity choices in the future are going to make the grid more vulnerable, or more resilient to climate change, dealing with things like transmission losses, thermal plant efficiency losses with extreme heat events, and wildfires, and obviously the loss of our Sierra snowpack.

The second overarching comment that I wanted to make was regarding the role of innovation and policy, so it seems like most of the parties today agree, including the two presentations from academic institutions that, no matter what, we're going to need some technology innovation to reach our 2050 emission reductions, and beyond. And what's more, we want this innovation to happen, and we want it to happen here because, you know, we want to be the state that's bringing in the venture capital money, and we want the tax revenues, we want the jobs associated with this innovation. And California sees real economic benefits to being out in front of some of these technologies.

That said, there's also been comment today about how additional policies shouldn't happen until we fully understand the impacts of higher increased levels of renewables and other clean energy technologies, and while I think it's important to understand the implications, I don't think -- I honestly don't think we're going to have all the answers before we start moving forward and, in fact, what drives a lot of the innovation is stretched policy goals, that's what sends the signal to the market that that's where the innovations are needed, so I don't think that we should be afraid to start talking about long term policy goals and aspirations while we continue to do the research about the implications and the costs.

I also wanted to just say that I think that the energy commission can be a really great convener of market participants, especially surrounding an area like Demand Response, where it seems like we have a lot of hope for it, but it hasn't been quite as tangible as we would like it to be. It seems like SMUD, DWP, and the ISO are all planning to make investments in the next year to catalogue the potential of Demand Response in the state, which I think is great, but then the question is, okay, so now what? So now that we know what the potential may be, what sorts of commitments are we going to make to actually making it happen? And I think that having this conversation in a public venue like the Energy Commission is a really great place to be realistic, but also create some accountability for moving forward on these resource potential assessments.

And then just really quickly, responding to Edison and PG&E, I think that Edison's -- what did you call it -- the preferred resource pilot project that you're going to do is a really great -- the living pilot -- is a really great example of actually moving forward and going beyond the theoretical and trying some stuff on the ground, and so I really look forward to hearing about your experiences. And obviously also understanding how you're defining the preferred resources and making sure that storage companies and Demand Response providers think that your definitions are realistic, so I really hope to see more of that.

And then I didn't have a lot of time to digest PG&E's concept of the total resource cost, carbon metric evaluation, but you know, my first reaction is that I think it's obviously very very important to do cost benefit analysis when we're talking about something as major as transforming the electricity grid and rate impacts. I do think it's really tricky and we have to be very clear what costs and benefits we include in this calculation, otherwise we're just going to get into the same vicious cycle of undervaluing the benefits of renewables and underestimating the costs of fossil fuel. There's a lot of additional reasons why we're investing in clean energy besides the energy savings, there are tangible public health benefits, there are very tangible and quantifiable portfolio diversity benefits that we don't want to lose in that calculation. So I'll leave it with that. Thank you.

MR. VESPA: Thanks. I'm Matt Vespa. I'm a Senior Attorney at the Sierra Club. And thank you for this opportunity to speak. Looking at planning for the energy grid of 2030 is very timely and it presents the opportunity to set forth next steps in choosing a low carbon future. And just building off the comments of Sierra and Laura, you know, we feel that we should be continuing to move to decarbonize our energy supply past 2020.

You know, one specific thing that will be interesting for the IEPR to look at for 2030 is an RPS of around 50 to 55 percent. What would those impacts be? You know, that would be continuing RPS growth around how it's growing between 2010 and 2020, you know, it seems to be more of a conservative growth level; more aggressively I'd like to see what it would it would take to go to 70 or 80 percent RPS by 2030. As scientists tell us, we're way behind our greenhouse gas goals, climate impacts are much more severe and cost much more than we ever thought, and we need to really accelerate our efforts to really deal with global warming. So what would it take to do that? And I think, you know, the IEPR can really serve as a visioning document to generate political will to achieve solutions. It may seem a 70 or 80 percent RPS by 2030 may seem quite high, but let's just look at what that would really mean.

And when we talk about the implications of increased penetration of renewables, you know, from Sierra Club's perspective, I think, you know, we've been very disappointed with the tenor of the dialogue. You see the duck graph, you see crisis, you see how are we ever going to deal with this. And I think the Commission can really play a role in setting out low carbon solutions. Sierra mentioned the pumped hydro, there's residential rates. We saw from SMUD an attempt to look at how EV charging policies can lower some of that. And so looking at higher renewable penetrations, and then looking at the solutions at how that duck graph can change over time. I think it will be really helpful and motivating and I think it would take some of the sort of hysteria out of renewables, and make more people see that there really are a lot of solutions out there that don't involve more fossil fuels that we should be looking to, you know, as we transition to a low carbon future.

COMMISSIONER MCALLISTER: Thanks for that. And I guess I want to reiterate the Chair's question at the beginning here about utility business models, and we're not going to solve that here today, but as we move towards a diversity of resources and investment needs that doesn't lend itself to -- it clearly needs to be disaggregated so it's sort of fixed at some volumetric, and it's going to look very different than what we've got today. What are the routing models that are going to allow those investments to be made, whether they're through the traditional utilities, PG&E and Edison, or in some other way. But there has to be enough collection to be able to maintain the infrastructure that we've got, whether or not there's any net procurement and sale of energy, so what's the vehicle for the revenue that the utilities -- that the load serving entities will be providing? And it seems to me that there's got to be some meeting of the minds on this in the fairly near term as, you know, I think there's a little bit -- I agree that there's a little bit of overblown quality to the discussion. I mean, net metering -- the structures are -- there's a grain of truth in there, you know, the structures of net metering, you can see them generating this sort of conflict out in the future, but we still have relatively low penetration, so it is not a crisis today. So we have some time to fix it. But I do think there needs to be some meeting of the mind among the various entities on all sides of this discussion so that we can actually say, "Okay, what is a healthy electric grid? What services is it providing? How do those services get paid for?" And I kind of feel like we're doing a lot of dancing around those questions, but not quite getting to it. And so, you know, not necessarily proposing a forum for that discussion at this point, I would totally be open to -- the IEPR could play a role in that, I mean, certainly there were forums over at the PUC, as well. I kind of feel like elevated across agency in a lot of ways, this is certainly not going to be decided within an individual agency because it's crosscutting. So there does need to be a broader discussion. So ideas about those bigger picture issues, I think, are really important to bring to the table. At some point here pretty soon, we're really going to have to chart that new direction.

MR. MARTINEZ: I'm glad you raised that issue of the utility business model of the future and what does rate structure look like in this carbon constrained future world. I think there has recently been a move towards a tendency to look at fixed charges, and I just want to highlight that, in any future rate design, we need to preserve the incentive to conserve and save energy. Customers need to be rewarded for the energy they are saving. And there are other options to make sure that a utility maintains its financial health and recovers sufficient revenues to afford to pay for the energy services that it delivers, and decoupling is a fantastic one. In the recent rate proceeding, we've discussed other alternatives such as variable demand charges, or bidirectional rate design, but regardless of how you go, the high fixed charge does not reflect actual high fixed cost. In the long run, almost all costs are variable. There are very few services, customer billing and service drops, perhaps a couple other, that actually are fixed, but the vast majority of costs in the long run are variable, and so we should preserve those volumetric rates to incentive customers to save energy.

CHAIRMAN WEISENMILLER: Yeah, although I

think everyone, just as you noted, decoupling, when we came up with that in late '70s, was very important to get the utilities moving on energy efficiency and to give them a business model that would work. Again, it is true over the longer term everything that's fixed is variable over the long term, or dead, and certainly the utilities could be, so I'm saying you really need to come up with a paradigm similar to decoupling that deals with the costs we need to sort of upgrade the grid to deal with the nature of what we're looking at in the future. It's not just moving powerful and large central station out to a house, powerful is every which direction, cars connected, you know, Demand Response, you name it, it's a very complicated system that's going to require investments to get there. And somehow we have to come up with -- again, you know, something creative like decoupling was to deal with the utility business model to make them comfortable. And again, at least they had the opportunity to exist, and we're not going to guarantee the existence to anyone, frankly, but at least to give them a fair shot at existing.

COMMISSIONER MCALLISTER: Well, and also, you know, Professor Friedman talked about, well, yeah, I think even if you're a Net Zero customer, if you've got a vehicle and you've got a large PV system, you know, for example, at any given moment there's a lot of energy flowing across that meter, and maybe you're Net Zero, but there certainly is a benefit to having the grid sitting there and that investment having been made. And so somebody has got to own that, somebody has got to maintain it, and that has real costs. And so what is the revenue associated? What is the revenue required to keep that system functioning even if we have 12 million DG systems producing all the energy and, you know, a bunch of storage around. You know, there's a lot of arbitrage going on, there's a lot of management of energy going on, and so I think if we think outside the box a little bit, we've got to come up with what is the customer paying for, what does the bill look like, and what is the customer paying for that provides value, that they feel decent about paying somebody for that service, even if they're, hey, sort of on net there, they're autonomous; they're not really, they're tied into the grid. So it's got a fixed cost -- so it's got a cost, you know, how much of it is fixed and how much of it is variable is certainly open to discussion.

MR. MARTINEZ: And I'm on board with making sure that customers pay for their fair usage of the grid, but in recovering the system infrastructure costs, having a fixed charge doesn't appropriately charge customers if one customer has a 20 kilowatt Electric Vehicle charger and the other has a 30.3 kilowatt; the fixed charge doesn't get towards that equity issue.

COMMISSIONER MCALLISTER: Fair point. Go ahead.

MR. VIDAVER: A couple of things. Remember, we have three objectives, affordability, reliability, and low environment impact. So this won't be a particularly cheery comment, but I just want to focus on the affordability piece and the business model. So, you know, one way that I think about it because it's part of my job, it's that when there's a policy driven investment that's above market, you know that it's going to be a 30-year life facility, so the question that comes to mind is, is this policy going to be in place for 30 years. So it's just something to think about.

In terms of how it gets funded, that's a great question. That's why when I talked a little bit about the carbon metric, you know, inviting particularly when you're starting out with a new technology, government funding or private equity funding is a nice way to go, it's not on utility customers at that point. In terms of when it moves to utility rates, you know, Chairman Weisenmiller mentioned earlier that you need at least a 10-year contract to finance this deal, that's been my experience on the procurement side, it takes about 10 years. So you'll have about a 10-year life in terms of utility customer commitment to an above-market commitment. If it's a utility investment, of course, it goes into rate base, and that's the third year. So you have to think about the duration of the policy. You know, just again, just from a cost point of view, not ignoring reliability and environmental impact, and for us when it's the utility, then who picks up that above market charge, and you've got other entities out there, load serving entities, that do not -- we get into the ever popular PUC proceeding around who and how do we allocate non-bypassable charges, and that's another inhibiting factor and it's something that makes us even less popular than just raising the cost issue is we need to allocate a portion of this to Marin Energy Authority, and it's just not a popular place to be, but from strictly a cost perspective, that one circle, those are some of the things you might need to think about.

And then I wanted to respond to the discussion of the carbon metric. Yes, you can argue about costs and benefits and go around and around on that and get nowhere, and I understand that. That's part of the reason when we did the analytics that we used three buckets, we weren't trying to get too precise with it, it falls into this bucket or that bucket, or the other bucket, and the idea that we had here in terms of social costs and benefits is that, if it falls in to that green bucket, or the amber bucket, you know, you think about how you move forward with it, you don't necessarily need to go to looking at societal costs and benefits. It's when you get into that red bucket that you start to have to ask yourself some additional questions: will the costs come down over time if you get started on this? Is there significant abatement that you may get? And, you know, let's look at that broader picture in terms of social costs and benefits and see if that changes the picture in terms of where it falls in that band. So, in a sense I'm trying to sort of facilitate that a little bit, and I don't know if it's a perfect concept, but that's the idea.

MR. VESPA: Just a comment specifically on net metering which was discussed in SCE's slide. I mean, in terms of the role of the Energy Commission, you know, my sense is the Public Utilities Commission has really squarely addressed the cost benefits of net energy metering and potential changes to the program. You know, from Sierra Club's perspective, it's really about properly evaluating costs and benefits before any changes are made. I know a petition was filed before the Energy Commission on evaluating social benefits, societal benefits on net energy metering, and I think that would be helpful in that discussion. You know what I have not seen the Public Utilities Commission take on, which is what Laura alluded to, which is why I mentioned in my comments, is really looking at implications of higher RPS scenarios because I think those are really important to understanding where we go in terms of legislation and future action. And I think that would be really helpful in this next IEPR to start exploring.

CHAIRMAN WEISENMILLER: Yeah, although again, there is an inconvenient truth of the grid, you know, certainly if you read the Resnick report, you've got to have a reliable grid and it's complicated. You point out hydro, but when you look at the hydro system overall, it's fewer -- we have less and less ability to rely on these situations. I guess the two examples I would come up with was back in the crisis, DWR contracted 300 megawatts of Demand Response; the number now is zero. You know, the ISO calls them, and if they can help they will, but they refuse to contract for any capability to help in part because of increasingly environmental constraints, and in part because of just human and equipment limitations. Or, similarly, when I first started really drilling into the PG&E system in the middle '80s, it was about twothirds pondage and one-third run of the river. And pondage is very controllable, run of the river is, you know, it just happens. And you know, at this point it's sort of flipped and you look at some things like Helms, you know, I remember certainly PG&E employees pushing for variable speed pumps and motors, but again, we need that variable speed pumps and motors throughout a lot of our hydro system, so it could do a lot, but it's really not -- at this point, it's really aging infrastructure, those were really not designed for renewable integration, and just the reality is there are increasing environmental constraints that will make more and more the hydro system run of the river unless controllable, so it's not a magic bullet, but certainly it's one of our best hopes.

COMMISSIONER MCALLISTER: I wanted to make a comment, too. This is a good out of the box discussion, so I think, you know, it's part of the reason why we're here. So cost-based service, you know, if we -- cost-based rates that reflect the costs of service for an individual customer, you know, we go down that road towards high differentiation, atomization, and at some point offering various services to various customers, depending on their qualities, and at some point, you know, we may be undermining sort of an underlying driver towards natural monopoly in the first place, right? So I think there's kind of an interesting discussion about, so what are the equity implications of that? Is it going to be sort of a gated community for the energy system? And underlying all this is sort of the question who owns the customer, I mean, I think that is really one of the questions that's front and center, Demand Response, for example, you know, are we really going to sort of open up that market and let the aggregators go after customers that the utility considers their customers? On EE, same sort of thing. Some of us are impatient to get service to get good quality, well informed services in front of energy users so that they can make better choices. And so is the system -- given our urgency with climate change, is the system capable -- is our regulatory structure capable of enabling that to happen? And I think there's just a lot of -- yeah, there's a need for this broader discussion about whether the utility business model can really incorporate that sort of urgency or not; and if not, then how does it need to change to be more adaptive? So I think that's a challenge. If I'm a utility today, I'm worried about my revenue and I'm trying to figure that out. And so, you know, this has everything to do with the long term investments that whatever system we have is going to be able to make in the long term to get to the timeframes that we're talking about, to get to the 2030 with a good solid reliable system. Who is going to make those investments? How are they going to recover the costs? So anyway, apologies for my riff here, but I think it's a really important set of issues to have on the table and there needs to be, I think, a forum that we can figure out how to create that forum. I think there are a lot people having similar discussions all over the state right now, and it would be nice to sort of have a little bit of a unification going on and figure this out for the long term so we can kind of get on with the test at hand, which is develop the businesses that are going to offer the services, that are really going to get it done.

MR. VESPA (presumed): Yeah, I would

really agree with that. I know internally at the Sierra Club, we talk about how do we get utility skin in the game so we can really see this deployment take off and not fight every step of the way, and I think certainly with the discussions it can be very just butting heads, so I think a forum like you suggest where you're really thinking creatively about solutions, that give the utility that business model, that 2.0 moving without undermining the deployment of DG&E and those types of things would be very helpful.

MS. WISLAND: And I'll just add, honestly I think a lot of people engaged in this discussion are not rate experts, unfortunately, and I think it would be helpful for the Commission to do a basic here that "here's all the components of a revenue requirement," just to start the discussions and so we're all on the same page because I know the utilities are required to submit reports to the Legislature, but at a very very high level, you know, so there's just one T&D block, you can't really dig into that and say, "Okay, here are all the investments, and here's the payback period for these investments, and here's where they've deferred investment, and here's where they haven't. And let's think through all these different investments that they have or have not been making." So it's difficult because I just think there's a lot of people talking about this, that feel very strongly about one resource or another, but are not rate experts.

CHAIRMAN WEISENMILLER: You know, though again, I think the challenge for everyone here -- and again, from my perspective, we're not going to guarantee the utilities, you know, in existence, but we at least have to have a framework similar to decoupling where in this area, again, they at least have an opportunity, it's just not a situation where their best customers are going to get picked off and picked off and picked off until finally, you know, they've got a situation where they made lots of long term investments and they can't recover the costs. You know, somehow or another you've got to at least -- otherwise, they're just going to fight you every step of the way, and they all have about 100 attorneys, they all have a couple very large reputable law firms on retainer, you know, and they can just try to pound you into the earth.

COMMISSIONER MCALLISTER: That's kind of the dynamic, right, is that without a clear long term play, the incentive to the utilities is to kind of think within the relatively traditional box and, you know, try to slow down things and make them nervous. And that's not a good place to be. So you know, the forum for that may not be here at the Energy Commission, it may be somewhere else, I hate to commit to the next IEPR lead to managing that discussion.

CHAIRMAN WEISENMILLER: Yeah, no, the PUC is having that en banc in October on Utility Business Models. For example, that would be the sort of question that should certainly be addressed there. And obviously Secretary Shultz, Grueneich's paper sort of really tries to raise the business model issue there, too. So, I mean, it's sort of bubbling in a lot of different directions. I think any number of academic institutions really want to try to dig their teeth into that in some fashion.

COMMISSIONER MCALLISTER: And that would be very helpful. So anyway, we sort of co-opted the discussion here, apologies for that. Anybody else want to chime in on anything they've heard today? Professor Friedman.

PROFESSOR FRIEDMAN: Thank you. I just would like to make a point that relates to energy efficiency and fixed charges. I completely agree with Sierra that, if you had one uniform fixed charge, that would reduce the incentive that people have for making energy efficiency investments. And I just want to be clear that, under a proposal like the ones that I've been making where you have a set of graduated fixed charges that are sort of proportional to the category of consumption that you're in, it becomes more visible, the idea would be that the utilities have a chance to offer prompt reclassification; for those households making substantial energy efficiency investments, to get categories down into the lower graduated fee. And the group of households that have been left out largely from energy efficiency have been the 60 percent of the least consuming households because of the tiered rate structure we have under the graduated fee rate structure, it's precisely those 60 percent of those households that would now have more incentive and more visible incentive to adopt energy efficiency improvements, to adopt solar, solar panels, so I just wanted to make that distinction between the graduated fee and the truly fixed uniform fee.

COMMISSIONER MCALLISTER: Great. Thanks very much. All right, we seem to have flattened the discussion. Let's think about questions and we have a little bit of time, but let's go to the public comment.

CHAIRMAN WEISENMILLER: Is there any public comment, or questions to the panel?

MS. KOROSEC: Yeah, anyone in the room who is interested in making a comment, please come up to the podium here. Yeah, go ahead. Just identify yourself for the record.

MS. BRAND: Hi. My name is Erica Brand. I'm Project Director at the California Renewable Energy Initiative at the Nature Conservancy in California.

First, thank you, Commissioners, for the opportunity to provide comments. I'm here to ensure the protection of natural resources remains part of the conversation today, about meeting 2030 and 2050 goals. I'm going to do that by sharing my perspective on the importance of incorporating land use planning into energy planning.

At the Nature Conservancy, we focus on using conservation science to inform decision making and policy development. We prefer to take a whole energy system perspective just as we do with ecosystems. So as we look towards 2030 to achieve a reliable, affordable, and sustainable electricity sector, we need to plan and manage for multiple goals, including a lot of the topics that we've discussed today, emission reduction, system reliability and operations, costs, and then protection of natural resources.

So to frame the challenge, we need to learn from the impacts we've already experienced. When we look at how energy policies have already been implemented on the ground, we've seen dozens of utility-scale projects deployed in areas of high ecological value, important for the protection and recovery of threatened and endangered species and long term conservation of biodiversity. So as we focus on expanding our clean energy future and look to where we should encourage innovation and deployment of new resources, electricity sector planning, procurement and markets should better integrate land use planning, including conservation science and available environmental data into decision making. Doing so provides value and minimizes risk.

We can use conservation science and environmental data to identify areas of least conflict, we can then create meaningful incentives in these areas for prioritizing resource deployment, including zones, development focus areas, and areas of least impact to promote investment, innovation and rapid scaling.

There's also value in incorporating information from critical efforts like the BLM Solar Energy Program, and the DRECP into energy planning. By doing this, we can leverage and maximize these investments that we're all making.

And lastly, there's value in early identifications of projects with high significant environmental and viability risks, and recognizing those early in planning and procurement processes.

So we appreciate the leadership that the CEC has taken thus far in both the DRECP and the IEPR, there was a workshop on May 7th about integrating environmental and land use data in planning, we encourage further discussion of that topic. And I have two specific examples of topics that would benefit from additional focus in near term analyses. So there's been discussion today of identifying preferred areas to locate resources for multiple benefits such as geographic diversity; I think Conservation science and environmental data should be an integral part of these processes. We need to take project scenarios that meet multiple goals, including locations with fewer environmental constraints to minimize project viability risks and costs. The second is that transmission remains a limiting factor, and also a driver, so how can we collectively work to unlock available or create new capacity in areas of least conflict from an environmental perspective? A specific near term example is the forthcoming development focus areas within the DRECP. How can we get capacity there so that projects will want to be sited in these areas that both trust agencies and energy agencies agree are the most appropriate for development in the desert?

So to close, we appreciate that the CEC

has created this space today to discuss 2030, we're supportive of the clean energy future, and want to see a framework that supports both deployment of resources, but also protection of areas of high conservation value. So, that's it.

CHAIRMAN WEISENMILLER: Okay, thanks for coming. You know, probably the same footnote I said at the beginning, those who want to influence the Scoping Plan should make sure the comments go into the Scoping Plan, as opposed to here, and similarly, in terms of affecting DRECP, certainly DRECP as opposed to necessarily here.

MS. BRAND: Thank you.

COMMISSIONER MCALLISTER: Definitely appreciate pointing out the linkages. And also, obviously, I don't know if we've said, but please do submit comments on today's workshop in the IEPR proceeding, so that we have it on the record and we can use it to help inform that IEPR, and remind us what day those are due, Suzanne?

MS. KOROSEC: Those are due on September 3rd, I believe, and I'll post at the end of the next steps, it has the information and the docket number to use for that.

COMMISSIONER MCALLISTER: Do we have any

participation on the web?

MS. KOROSEC: We do have one question or comment from online, it's from Shalini Swaroop. Can you go ahead and unmute the line?

MS. SWAROOP: Hi. This is Shalini Swaroop from the Marin Energy Authority. And I was wondering have any of the projections for load today included any community choice load projections, and does the CEC plan to include community choice aggregation load projections into the IEPR?

CHAIRMAN WEISENMILLER: At this point, they're sort of buried. I mean, I think certainly the question, as we do with the POUs, we tend to reach out to them and try to get information from them, and so certainly as we move forward in the future it would be certainly interesting to reach out to Marin and get the type of data we would need and the types of forecasts you have to see if we can disaggregate it, although, again, you may find this enough of a pain in the neck that you'd prefer to deal with PG&E or have it handled under the PG&E umbrella.

MS. SWAROOP: I think that would be quite a pain in the neck, so I appreciate that. Thank you.

COMMISSIONER MCALLISTER: Thank you.

MS. KOROSEC: All right, we have no other WebEx participants, but we do have phone callers, so I'd like to just open, we have three callers that have still hung in here until the bitter end. Just open the lines just to make sure if anyone has any comments. So go ahead and open the lines. All right, phone participants, your lines are open if you have any questions or comments. All right, hearing none, I think we have -- I'll do one more test of the room -- anybody else want to make any final comments?

COMMISSIONER MCALLISTER: Any final comments from anybody? And if not, I want to thank everybody for coming, really enjoyed the presentations and thanks for the final panel for sticking around until the bitter end here, and yeah, I think we've talked about a lot of interesting things today, all very important. I think part of -- we have a very robust Democracy here in California and that's a good thing, and it also means that there's a lot of voices in the room, there are a lot of stakeholders in any given issue, and doing long term planning is very challenging. And so I think it takes a little bit of extra effort to get it done in a place like this. But at the end of the day, we end up coming up with things that are innovative, that in general I think we can say they get after a couple of iterations maybe, they get the result that we're looking for. And I think this longer term discussion was a little bit more free-formed than maybe we generally have here at the Commission is really a good thing and it helps us all keep our thinking caps finely tuned. So thanks again everybody for coming and participating, and please do submit your comments for the record so we can have those at our service.

CHAIRMAN WEISENMILLER: Yeah, and again, certainly what will be useful is to think about the types of methodologies we should use. I mean, one footnote on this question of renewable integration, you know, one of the things which certainly I have been asking the ISO to do with the more detailed studies of 50 percent, you know, the sort of spreadsheets we have don't really give you any insight into those issues, but certainly going forward, it's sort of, again, it's a new area for us, we typically don't do scenario planning per se, and so we're trying to develop the tools for that and obviously the tools have to be scoped around what are the policy issues. And in some areas, again, you know, maybe things come again from very detailed models, another area simplified stuff, but as you go further out in the future there's greater and greater uncertainty, so trying to really crunch through the detailed stuff can be just spinning your wheels.

So again, thanks for being here. We're looking forward to your comments.

COMMISSIONER MCALLISTER: I think we're adjourned. Thanks very much.

MS. KOROSEC: Thank you.

(Thereupon, the Workshop was adjourned at 4:38 p.m.)

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